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BEFORE THE ARIZONA CORPORATION COMMISSION

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Arizona Corporation Commission
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DOUG LITTLE – Chairman
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ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	Docket No. E-01345A-16-0036
IN THE MATTER OF FUEL AND PURCHASED POWER PROCUREMENT AUDITS FOR ARIZONA PUBLIC SERVICE COMPANY.	Docket No. E-01345A-16-0123 **NOTICE OF FILING REDACTED DIRECT TESTIMONY (REVENUE REQUIREMENT) AND EXHIBITS OF KEVIN C. HIGGINS ON BEHALF OF FREEPORT MINERALS CORPORATION, ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION**

Freeport Minerals Corporation, Arizonans for Electric Choice and Competition (collectively "AECC"), hereby submit the Redacted Direct Testimony (Revenue Requirement) and Exhibits of Kevin C. Higgins on behalf of AECC in the above captioned Docket.

For the parties who have signed the Arizona Public Service Company ("APS") Protective Agreement, they will be able to view the confidential portion of Mr. Higgins' Testimony by accessing the APS Rate Case website.

FENNEMORE CRAIG
PROFESSIONAL CORPORATION
PHOENIX

RESPECTFULLY SUBMITTED this 28th day of December, 2016.

FENNEMORE CRAIG, P.C.

By ______________________

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FILED this 28th day of December, 2016 with:

Docket Control
ARIZONA CORPORATION COMMISSION
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Phoenix, Arizona 85007

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BEFORE THE ARIZONA CORPORATION COMMISSION

In the Matter of the Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop Such Return)	Docket No. E-01345A-16-0036
In the Matter of Fuel and Purchased Power Procurement Audits for Arizona Public Service Company)	Docket No. E-01345A-16-0123

REDACTED

Direct Testimony of Kevin C. Higgins

on behalf of

Freeport-McMoRan Copper & Gold Inc. and

Arizonans for Electric Choice & Competition

Revenue Requirement

December 28, 2016

DIRECT TESTIMONY OF KEVIN C. HIGGINS

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DIRECT TESTIMONY OF KEVIN C. HIGGINS

I. INTRODUCTION

Q. Please state your name and business address.

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by Freeport-McMoRan Copper & Gold Inc. and Arizonans for Electric Choice and Competition ("AECC"). AECC is a business coalition that advocates on behalf of retail electric customers in Arizona.[1]

Q. Please describe your professional experience and qualifications.

A. My academic background is in economics, and I have completed all coursework and field examinations toward the Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist

[1] Henceforth in this testimony, Freeport-McMoRan Copper & Gold Inc. and AECC collectively will be referred to as "AECC."

private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. Have you testified before this Commission in other dockets?

A. Yes. I have testified in approximately twenty proceedings before this Commission, including the generic proceeding on retail electric competition (1998),[2] the hearings on the Arizona Public Service Company ("APS") 1999 Settlement Agreement (1999),[3] the hearings on the Tucson Electric Power ("TEP") 1999 Settlement Agreement (1999),[4] the AEPCO transition charge hearings (1999),[5] the Commission's Track A proceeding (2002),[6] the APS adjustment mechanism proceeding (2003),[7] the Arizona ISA proceeding (2003),[8] the APS 2004 rate case (2004),[9] the Trico 2004 rate case (2005),[10] the TEP 2004 rate review (2005),[11] the APS 2006 interim rate proceeding (2006),[12] the APS

[2] Docket No. RE-00000C-94-0165.
[3] Docket Nos. RE-00000C-94-0165, E-01345A-98-0471, and E-01345A-98-0473.
[4] Docket Nos. RE-00000C-94-0165, E-01933A-97-0772, and E-01933A-97-0773.
[5] Docket No. E-01773A-98-0470.
[6] Docket Nos. E-00000A-02-0051; E-01345A-01-0822; E-00000A-01-0630; E-01933A-02-0069; E-01933A-98-0471.
[7] Docket No. E-01345A-02-0403.
[8] Docket No. E-00000A-01-0630.
[9] Docket No. E-01345A-03-0437.
[10] Docket No. E-01461A-04-0607.
[11] Docket No. E-01933A-04-0408.
[12] Docket No. E-01345A-06-0009.

2006 rate case (2006),[13] TEP's request to amend Decision No. 62103 (2007),[14] the TEP 2007 rate case (2008),[15] the APS 2008 rate case (2008),[16] the APS 2011 rate case (2011-12),[17] the TEP 2011 Energy Efficiency Plan (2012),[18] the TEP 2012 rate case (2012),[19] the APS Four Corners Rate Rider proceeding (2014),[20] the UNSE Electric, Inc. 2015 rate case (2015),[21] the TEP 2015 rate case (2016),[22] and the Southwest Gas Corporation 2016 rate case (2016).[23]

Q. Have you testified before utility regulatory commissions in other states?

A. Yes. I have testified in approximately 190 other proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arkansas, Colorado, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, New York, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, Texas, Utah, Virginia, Washington, West Virginia, and Wyoming. I have also participated in various Pricing Processes conducted by the Salt River Project Board and have filed affidavits in proceedings at the Federal Energy Regulatory Commission.

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[13] Docket No. E-01345A-05-0816.
[14] Docket No. E-01933A-05-0650.
[15] Docket No. E-01933A-07-0402.
[16] Docket No. E-01345A-08-0172.
[17] Docket No. E-01345A-11-0224.
[18] Docket No. E-01933A-11-0055.
[19] Docket No. E-01933A-12-0291.
[20] Docket No. E-01345A-11-0224.
[21] Docket No. E-04204A-15-0142.
[22] Docket No. E-01933A-15-0322.
[23] Docket No. G-01551A-16-0107.

II. OVERVIEW AND CONCLUSIONS

Q. What is the purpose of your testimony in this phase of the proceeding?

A. My testimony addresses four major topics:

(1) APS's stated request for a base rate increase of $433.4 million relative to test year base revenues, or a net increase of $165.9 million;

(2) APS's request for deferred accounting treatment for its Ocotillo modernization and expansion project and its Four Corners selective catalytic reduction ("SCR") projects, along with the Company's requested step increase for the latter;

(3) The importance of reinstating a sharing mechanism as part of calculating the Power Supply Adjustor ("PSA"); and

(4) APS's proposals to increase charges to customers through the Environmental Improvement Surcharge ("EIS").

Relative to the wide scope of this general rate proceeding, my recommended adjustments are concentrated on a limited number of issues. Absence of comment on my part regarding a particular issue does not signify support (or opposition) toward the Company's filing with respect to the non-discussed issue.

Q. What are the primary conclusions and recommendations presented in your testimony?

A. (1) I recommend that APS's revenue requirement for its base rates be reduced by at least **$91.312** million relative to the $433.4 million base rate increase proposed by APS in its Application. This recommendation translates into a reduction of **$81.333** million relative to the $165.9 million net increase to customer rates presented by APS in its direct testimony. This reduction does not take into account any reasonable adjustments that may be offered by other parties that are not addressed in my direct testimony.

(2) I recommend that APS's request for deferral mechanisms for its Ocotillo and Four Corners SCR projects be denied and that its requested step rate increase for the Four Corners SCRs be denied.

(3) I recommend that the Commission restore the sharing provision in the PSA that was eliminated in the last general rate case.

(4) I recommend that APS's proposals to increase charges to customers through the EIS be rejected.

III. ADJUSTMENTS TO REVENUE REQUIREMENT

Q. What increase in base revenues is APS requesting in this case?

A. In its Application, APS is recommending a base rate increase of $433.4 million relative to test year base revenues. This increase includes the net effects of several important surcharge rider components: (1) an increase of $128.6 million related to the transfer of Transmission Cost Adjustment (TCA) rider costs into base rates; (2) an increase of $57.6 million related to the transfer of Four Corners rider costs into base rates; (3) an increase of $46.0 million related to the transfer of Lost Fixed Cost Recovery (LFCR) rider costs into base rates; (4) an increase of $37.5 million related to the transfer of Renewable Energy Adjustment Charge (REAC) rider costs into base rates; (5) an increase of $10.0 million related to the transfer of Demand Side Management (DSM) rider costs into base rates; (6) an increase of $2.5 million related to the transfer of Environmental Improvement

Surcharge (EIS) rider costs into base rates; and (7) a decrease of $14.6 million related to the transfer of System Benefit Surcharge (SBC) rider costs into base rates. After netting the effects of the transfer of these surcharge rider components, the net base rate increase embedded in APS's proposal – as depicted by the Company – amounts to $165.9 million.

Q. Why do you qualify your description of the net rate increase by using the phrase "as depicted by the Company"?

A. APS's calculation of a net increase of $165.9 million incorporates a $41.625 million reduction in base fuel costs relative to the test year, based on a projected reduction in base fuel costs from 3.1359 cents/kWh incurred during the test year to 2.9882 cents/kWh, as discussed in the direct testimony of APS witness Peter M. Ewen.[24] However, since its filing, APS has revised its projection of 2017 fuel costs upward to 3.1610 cents/kWh,[25] which is $48.598 million greater than depicted by APS in its filing.[26] Since under the operation of the PSA, as currently structured, APS will be able to pass on 100% of any increase in fuel costs to customers, the *real* expected net change in rates to customers in 2017 relative to the test period is significantly greater than APS depicts in its filing, once the operation of the PSA is taken into account.

Q. Do you have any recommended adjustments to APS's proposed base rate increase?

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[24] Direct Testimony of Peter M. Ewen, Attachment PME-3DR.

[25] *See* APS's Third Supplemental Response to Staff Data Request 1.13, APSRC01514, included in Exhibit KCH-1. Moreover, the Company's September 30, 2016 PSA filing shows a projected net fuel cost of 3.3166 cents/kWh for the 2017 forward component. *See* Docket Nos. E-01345A-05-0816, et al., APS September 30, 2016 annual update

[26] This calculation is presented in Exhibit KCH-2.

A. Yes. I am recommending a reduction of **$91.312** million to APS's proposed base rate increase relative to the Company's Application. My recommendation relative to base rates is presented in Exhibit KCH-3 and is summarized in Table KCH-1, below. My recommendation relative to the net increase to customers is also presented in Exhibit KCH-3 and is shown in Table KCH-2, below. Each of my adjustments will be discussed in turn. However, prior to discussing my recommended adjustments, I believe it would be useful to have a discussion of test period in the context of APS's filing.

Table KCH-1

Summary of AECC Adjustments to APS Revenue Requirements
(Base Rates)[27]

	Original Cost Increase/ (Decrease) ($000s)	Fair Value Increase/ (Decrease) ($000s)	Total Increase/ (Decrease) ($000s)	Total Adjustment Impact ($000s)
APS - As Filed Requested Base Increase	**$ 381,568**	**$ 51,866**	**$ 433,434**	
AECC Depreciation Expense Adjustment	**371,908**	**51,866**	**423,774**	**(9,660)**
AECC Payroll Expense Adjustment	**370,114**	**51,866**	**421,980**	**(1,794)**
AECC Cash Incentive Expense Adjustment	**350,327**	**51,866**	**402,193**	**(19,787)**
AECC DSMAC Expense Adjustment	**340,348**	**51,866**	**392,214**	**(9,979)**
AECC STAR Center Patents Adjustment	**339,882**	**51,866**	**391,748**	**(466)**
AECC ADIT Adjustment	**335,992**	**51,866**	**387,858**	**(3,890)**
AECC Return on Equity	**290,256**	**51,866**	**342,122**	**(45,736)**
AECC Adjustment Total				**$(91,312)**

[27] Table KCH-1 and Table KCH-2 do not include the $48.5 million rate increase impact associated with APS's updated base fuel and purchased power costs. See APS's Third Supplemental Response to Staff Data Request 1.13, APSRC01514, included in Exhibit KCH-1.

Table KCH-2

Summary of AECC Adjustments to APS Revenue Requirements
(Net Rates)

	Total Increase/ (Decrease) ($000s)	Total Adjustment Impact ($000s)
APS - As Filed Requested Net Increase	**$ 165,883**	
AECC Depreciation Expense Adjustment	**156,223**	**(9,660)**
AECC Payroll Expense Adjustment	**154,429**	**(1,794)**
AECC Cash Incentive Expense Adjustment	**134,642**	**(19,787)**
AECC DSMAC Expense Adjustment	**134,642**	**0**
AECC STAR Center Patents Adjustment	**134,176**	**(466)**
AECC ADIT Adjustment	**130,286**	**(3,890)**
AECC Return on Equity	**84,550**	**(45,736)**
AECC Adjustment Total		**$(81,333)**

Test Period Issues

Q. What is meant by the term "test year" as used in ratemaking?

A. "Test year" refers to a discrete twelve-month period that is used as the basis for setting utility rates in a general rate proceeding. This term is often used interchangeably with the term "test period," although some jurisdictions make a fine distinction between the two, with "test year" referring to the baseline period for which underlying historical financial and operating data must be reported and "test period" referring to the twelve-month period used for setting rates. When this distinction is made, test year and test period can be coterminous, overlapping, or entirely distinct time periods.

Q. What test year is APS using in its application?

A. APS is proposing to use the Calendar Year 2015 for revenue requirement purposes. As such, APS begins its analysis by presenting a Calendar Year 2015 baseline that sets out the Company's twelve-month revenue, expense, and investment levels. These results are then adjusted for ratemaking purposes, which is typical in most general rate proceedings. However, in APS's filing, the adjustments to the historical test year are "brought forward" quite significantly. While the basis of the Company's filing starts with 2015 actual revenues, expenses, and investment, the filing incorporates various revenue, expense, and investment elements that are adjusted for values that either occurred or are projected to occur variously in 2016 or 2017, including "annualizations" projected for June 30, 2017. While APS's "adjusted test period" defies a clear and consistent description with respect to the time period it depicts, in many respects it most reflects the period from July 1, 2017 through June 30, 2018.

For example, on an ACC jurisdictional basis, $1.088 billion of gross post-test year plant that is projected to be added through June 30, 2017 is included by APS in rate base.[28] Significantly, APS proposes to value this plant for ratemaking purposes at its *end-of-period* value (i.e., on June 30, 2017), thus reflecting its value at the start of the period from July 1, 2017 through June 30, 2018. Similarly, depreciation expense is annualized using the projected plant balances on June 30, 2017, and thus reflects the depreciation expense projected for the post-test year plant for the period from July 1, 2017 through June 30, 2018, rather than the (significantly lower) depreciation expense that is actually going to be incurred for the post-test year plant for the prior year, July 1, 2016 through June 30, 2017.

Yet another example is payroll expense. APS annualizes its payroll expense based on March 2016 employee and wage levels, and adjusts this amount

[28] Derived from APS Schedule B-2.

for scheduled salary increases for union employees, up to and including increases projected for April 2017. Significantly, the payroll expense is also annualized; that is, payroll expense not only incorporates wage increases projected for the future, the increases are included in expense for their full 12-month value, even if they were only applicable for several months prior to June 30, 2017.

Q. Do you believe that APS's end-of-period rate base treatment for post-test year plant is reasonable?

A. No, I do not. The sole justification for using an end-of-period rate base is to address utility concerns about regulatory lag. According to the regulatory lag argument, utilities are challenged to earn their authorized rates of return on investment during periods of system expansion when historical test periods are used for setting rates. One means of reducing regulatory lag is to use a projected test period – or in this instance, an adjustment for projected plant additions – rather than a strictly historical measurement period. An entirely separate means of reducing regulatory lag is to adjust rate base in an <u>historical</u> test period to an end-of-period value, as this will cause the utility's authorized rate of return to be applied to the year-ending value of net plant in service. However, in offering its plant additions adjustments, APS proposes to combine <u>both</u> a projected measurement period <u>and</u> an end-of-period rate base. This "doubling up" of attrition mitigation approaches is unreasonably aggressive.

In contrast, a less aggressive and more reasonable approach would value the post-test period plant on an *average* basis, calculated using the average monthly value of the new plant as it was projected to be added over the course of the period July 1, 2016 through June 30, 2017. This latter approach is known as "average-of-period" rate base. In my opinion, an average of period rate base is more reasonable and appropriate when using a projected test period (i.e., a test period that ends in the future relative to the filing date of the rate case).

In sum, an end-of-period rate base should only be contemplated when applied to an historical test period or measurement period. The proper measurement for a projected rate base is average-of-period value. Since the value of rate base changes each month as new plant is added and existing plant depreciates, determining rate base by averaging each month's value ensures that the asset base upon which the utility will earn a return is reflective of its "typical" value during the course of the test period or measurement period.

Q. Have you prepared an adjustment that converts APS's end-of-period rate base into an average-of-period value?

A. No, I have not. Calculation of an average-of-period rate base requires detailed information regarding monthly plant balances, accumulated depreciation, and accumulated deferred income tax. This information is not well-documented in APS's filing and has been difficult to obtain in usable form in discovery.[29] Consequently I have not prepared an adjustment that restates APS's post-test year plant on an average-of-period basis. Nonetheless, I am registering my objection to the Company's approach and I do propose several adjustments relating to expenses that are concerned with this issue of the appropriate "effective" test period for ratemaking. Further, I recommend that the Commission require APS in future rate proceedings to prepare any post-test year plant adjustments on an

[29] For example, APS's workpapers list the in-service date for a number of plant additions as 6/30/17, although APS claims that these additions represent "projects," with components going into service throughout the post-test year period. See APS's Response to AECC Data Request 9.2 and APS's Response to AECC Data Request 9.1, which are included in Exhibit KCH-1.

average-of-period basis or, at a minimum, provide all the information necessary for such a calculation (e.g., monthly plant balances, monthly accumulated depreciation, monthly accumulated deferred income tax) as part of its filing.

Q. What do you mean by the "effective" test period for ratemaking?

A. By "effective" test period, I am referring to the test period that is actually being used for ratemaking purposes after adjustments are taken into account. As I stated above, nominally APS is using a 2015 Calendar Year test year. But after adjustments, it most closely resembles a test period covering July 1, 2017 through June 30, 2018. That is, even though APS does not add any *new* plant or *new* expenses to rates after June 30, 2017, by measuring rate base at an end-of-period value and annualizing expenses to end-of-period levels, rate base and expense for items providing service on June 30, 2017 are set at the starting level for the *subsequent* year.

Q. But isn't APS supposed to be using an *historical* test year for setting rates?

A. R14-2-103 defines test year as "the one-year historical period used in determining rate base, operating income and rate of return." While R14-2-103 allows for pro-forma adjustments to actual test year results and balances to obtain a normal or more realistic relationship between revenues, expenses, and rate base, the rule also states that "the end of the test year shall be the most recent practical date available prior to the filing." While I can offer no legal opinion on this language, one possible interpretation is that only historical test periods may be used to set rates in an APS rate case. However, each of the last several APS rate cases have featured substantial post-test period plant additions measured at end-of-period values, as well as annualizations of expense items that go well beyond the end of the nominal test period – in this proceeding 18 months beyond. Based on my experience in ratemaking, I would characterize the effective test period used by APS to be a fully-projected test period. Legal questions aside, a key policy question then is: how aggressively-forward should the effective test period be allowed to be? In my opinion, APS's test period adjustments reach too far forward. If APS is permitted to recognize rate base and expense adjustments through June 30, 2017, as the Company is requesting, then APS should <u>not</u> also be allowed to further adjust these amounts to their end-of-period values.

Depreciation Expense Adjustment

Q. Please explain your depreciation expense adjustment.

A. I am recommending an adjustment to depreciation expense to synchronize the depreciation expense recovered in rates with the accumulated depreciation that is reflected in APS's proposed rate base.

As I discussed above, APS is proposing post-test year rate base adjustments, adding $1.088 billion in gross plant that is projected to come into service between January 1, 2016 and June 30, 2017. As I explained above, for rate base purposes, APS values this plant at its end-of-period value (i.e., its projected value on June 30, 2017), rather than at its average-of-period value (i.e., its average value over the last 12 months of the post test-year period). APS's end-of-period approach produces a higher post-test year plant rate base valuation than an average-of-period approach would. APS also annualizes depreciation expense for the post-test year plant; that is, rather than use projected *actual* depreciation expense for the 12-month period ending June 30, 2017 for ratemaking purposes, APS instead calculates a higher depreciation expense that is applicable to the end-of-period plant value. APS proposes to use this higher going-forward depreciation expense for ratemaking purposes; in effect, APS proposes to recover depreciation expense for the post-test year plant that is based on the projected expense for the *subsequent* year, i.e., July 1, 2017 through June 30, 2018.

However, APS's calculation of *accumulated depreciation* for the post-test year plant is not synchronized with its end-of-period treatment of plant-in-service or its annualization of depreciation expense. That is, the Company's rate base projection does not reflect a full-year's value of accumulated depreciation for the post-test year plant. Put another way, APS seeks the maximum valuation for its gross plant-in-service (end-of-period) and the maximum value for its depreciation expense (annualized) but does not include a full year's accumulated depreciation based on the end-of-period plant valuation. This is a significant inconsistency because accumulated depreciation is a credit against rate base and thus benefits customers. My adjustment corrects for this inconsistency by reducing APS's depreciation expense for post-test year plant to be consistent with its treatment of accumulated depreciation. In essence, I am recommending that the end-of-period annualization of depreciation expense for post-test year plant be denied. This adjustment is presented in Exhibit KCH-4. I estimate that it reduces APS's retail revenue requirement by **$9.660** million.

Payroll Expense Adjustment

Q. Please explain your payroll expense adjustment.

A. As I discussed above, even though APS is nominally using a 2015 historical test year, the Company adjusts its payroll expense to include scheduled wage increases for union employees through April 2017. APS then annualizes this increase; that is, payroll expense increases are included in expense for their full 12-month value, even if they were only applicable for several months prior to June 30, 2017.

I disagree with the aggressive expense annualization employed by APS. Instead, my adjustment allows APS to recover its projected wage increase in April 2017, but only for the months in which it would apply for an effective test period from July 1, 2016 through June 30, 2017.

My payroll expense adjustment is presented in Exhibit KCH-5. I estimate that it reduces APS's retail revenue requirement by **$1.794** million.

Cash Incentive Compensation Adjustment

Q. Please describe APS's cash incentive plan.

A. APS provides an annual incentive award plan for its eligible employees, which determines cash awards based on a combination of Company financial performance, business unit performance, and individual performance. Each business unit performance plan includes a Shareholder Value component.[30]

Q. What has APS proposed with respect to cash incentive compensation?

A. APS is proposing to include 100 percent of the ACC-allocated cash incentive compensation expense in rates, based on the average of cash incentive expense for 2013, 2014, and 2015.

[30] See APS's Response to AECC Data Request 6.1, which is included in Exhibit KCH-1.

Q. In your opinion, is it appropriate to recover the cost of annual cash incentive compensation plans in utility rates?

A. It can be appropriate to recover the cost of annual incentive compensation plans in utility rates to the extent that the compensation in such plans is not excessive and to the extent the goals of such plans are not tied to utility financial performance, but rather to goals such as customer satisfaction, operating efficiency, and safety. While rewarding employees for financial performance can be entirely appropriate, the responsibility for funding such awards rests most appropriately with shareholders, who are the primary beneficiaries of meeting or exceeding financial targets.

Q. What is your recommendation to the Commission regarding recovery of annual incentive compensation expense?

A. I recommend that shareholders fund 55 percent of the normalized annual cash incentive compensation expense, based on the total share of APS's cash incentive expense that is related to financial performance. According to APS's responses to discovery,[31] approximately 40 percent of the total average cash incentive expense between 2013 and 2015 was based on Company financial performance, and an additional 15 percent of the average total cash incentive expense was based on Shareholder Value from the business unit performance component. My recommended adjustment is presented in Exhibit KCH-6. My adjustment reduces APS's ACC jurisdictional revenue requirement by approximately **$19.787** million relative to APS's filed case.

[31] APS's Responses to AECC Data Requests 6.1 and 15.1.

APS Proposal to Shift DSM Costs into Base Rates

Q. What is APS proposing regarding the treatment of DSM costs in this case?

A. APS is proposing to shift approximately $10.0 million in costs that are currently recovered through the DSM Adjustor Charge ("DSMAC") into base rates.

Q. What rationale does APS offer for this proposed change?

A. In her direct testimony, Barbara D. Lockwood explains that APS's major motivation for rolling an additional $10 million in DSMAC costs (along with all TCA costs) into base rates is "to protect these vital revenue streams from the ongoing attacks by some intervenors against rate-adjustment mechanisms."[32] Ms. Lockwood also explains that some believe that adjusters complicate the bill and sometimes make customers believe they are paying twice for the same cost.

Q. What is your assessment of APS's proposal?

A. APS's proposal to shift DSM cost recovery from the DSMAC into base rates should be rejected. While this issue is fundamentally a matter of rate design, I am addressing it here in my Revenue Requirement testimony because it has implications for the setting of base rates.

The shifting of costs from the DSMAC into base rates would result in a loss of transparency regarding the cost of the Company's energy efficiency programs. This information should not be obfuscated and hidden from customers. APS already has $10 million in DSM costs included in base rates. If any DSM costs are shifted, it would be more appropriate to move these dollars from base rates to the DSMAC in the interest of transparency. APS's proposal to artificially

[32] Direct Testimony of Barbara D. Lockwood, p. 17.

reduce the DSMAC by shifting DSM costs into base rates creates a potential for misinterpretation. Such a shift could cause customers to mistakenly believe that the costs of the Company's DSM programs are limited to those costs that appear in the surcharge. Erroneous inferences of this sort should be avoided. Public policy should err on the side of disclosure and transparency.

Further, the shifting of DSM costs into base rates would complicate efforts to move toward base rate parity across customer classes. Currently, the majority of energy efficiency costs are already reasonably allocated through the design of the DSMAC. But to the extent that DSM cost recovery is moved from the DSMAC into base rates, it would undo the reasonable cost allocation achieved through the DSMAC and would likely add to the problem of trying to attain base rate parity.

A specific example of this problem pertains to Freeport McMoRan's Bagdad facility, which was granted an exemption from the DSMAC by the Commission because the Bagdad facility meets the exemption criteria of having an active DSM program at a single site of 20 MW or greater.[33] Shifting DSM cost recovery from the DSMAC into base rates undermines the Commission's exemption order in that it shifts DSM cost recovery to the Bagdad facility, which does not participate in, benefit from, or pay for DSMAC-related costs. Burying DSM costs in base rates makes it difficult to identify who is paying for them. Such an action is not in the public interest.

Q. What is the impact on the base revenue requirement of your recommendation?

[33] *See* Docket No. E-01345A-14-0261, Decision No. 74813 at 4.

A. My recommendation is presented in Exhibit KCH-7. As shown in Table KCH-1, it reduces APS's jurisdictional base revenue requirement by **$9.979** million. However, as shown in Table KCH-2, this adjustment has no effect on APS's net revenue increase because it is revenue neutral on an overall basis.

STAR Center Patent Rights Adjustment

Q. What is the APS STAR Center?

A. The Solar Test and Research (STAR) Center, which opened in 1985, was an innovation center and solar plant in Tempe where APS collaborated with manufacturers, universities and government laboratories to develop and test emerging technologies applicable to APS's business.[34] Ratepayers historically have provided funding for the STAR Center, although generally the costs were included as general operating costs and are not distinguishable as STAR Center costs.[35]

Q. What are the STAR Center patent rights?

A. APS developed two types of solar tracking systems at the STAR Center, a single-axis tracker and a dual-axis tracker, which increase electrical output compared to a non-tracking system. In 2009, APS filed an application for authorization to sell the patent rights for the tracking systems to Unirac, Inc., an American solar racking manufacturer. As part of the purchase agreement, APS

[34] Docket No. E-01345A-09-0357, APS July 14, 2019 Application.
[35] *See* APS's Response to AECC Data Request 8.1, which is included in Exhibit KCH-1.

retained a broad license to use the technology underlying the patent rights, but could not sell or market the solar tracking technology for three years.[36]

The Commission authorized the sale of the patent rights and ordered that the future ratemaking treatment of the transaction should be determined in future APS rate cases.[37]

Q. What ratemaking treatment does APS propose for the STAR Center patent rights proceeds?

A. APS proposes to pass 50% of the $2.25 million proceeds on to customers, by amortizing the balance over three years. A regulatory liability was also created representing 50% of the proceeds.[38]

Q. What ratemaking treatment do you recommend for the patent rights?

A. I recommend that any sharing of the proceeds be treated in a consistent manner with any sharing mechanism in the PSA, discussed below in my testimony. If the sharing provision in the PSA is not reinstated, then I recommend that 100% of the proceeds be passed on to customers. The solar tracking technologies were developed by APS through activities at the STAR Center applicable to APS's regulated business. Ratepayers provided funding for the STAR Center, and it is appropriate that, under current ratemaking practices, customers should receive the full benefit of technologies developed there, including intangible assets such as patent rights. Therefore, I recommend treating the 50% portion of the proceeds that APS had intended to reserve for shareholders ($1.125 million) in the same way that APS proposed to treat the other 50%

[36] Docket No. E-01345A-09-0357, APS July 14, 2019 Application.
[37] Decision No. 71629, April 14, 2010.
[38] Direct Testimony of Elizabeth A. Blankenship, p. 18, lns. 19-23 – p. 19, ln. 2; *see* also APS's Response to AECC Data Request 4.1, which is included in Exhibit KCH-1.

intended for customers, by amortizing it over three years, and by recognizing a regulatory liability for the balance.

My adjustment for STAR Center Patent Rights is presented in Exhibit KCH-8. I estimate that assigning 100% of the proceeds to customers reduces APS's retail revenue requirement by **$0.466** million.

However, if the Commission adopts my recommendation that a sharing mechanism should be reinstated in the PSA, then the proceeds from the STAR Center patent rights should be shared in the same proportions applicable to the PSA.

Q. Why do you believe there should be consistency between the sharing of benefits from the APS STAR Center patent rights and a sharing provision in the PSA?

A. In both instances, a core consideration is whether it makes sense for customers and the Company to mutually share in benefits and/or costs when Company performance is an important factor in determining an outcome. Philosophically, I can see the merit in allowing the Company to share in the benefit from taking a positive action such as selling patent rights; however, I strongly object to an asymmetrical approach in which the need for an incentive is recognized in sharing a *reward* with the Company, but the need for incentives is somehow *not* recognized when it comes to sharing costs, benefits, and risks through the operation of the PSA.

Accumulated Deferred Income Tax (ADIT)

Q. What is accumulated deferred income tax?

A. Companies are generally able to take advantage of accelerated depreciation for tax purposes. The difference between the income taxes based on straight-line depreciation and the actual taxes paid by the Company are considered to be deferred taxes. Utilities book this difference into an account called Accumulated Deferred Income Tax ("ADIT"), which represents the cumulative value of deferred income taxes over time.

Q. Generally, how is ADIT reflected in utility ratemaking?

A. Regulatory authorities, including this Commission, recognize that utility depreciation for tax purposes differs from utility book depreciation used in ratemaking. Generally, the tax benefits of accelerated depreciation are not passed through *directly* to ratepayers, but rather certain indirect benefits are recognized through the determination of rate base. According to the conventions of income tax normalization, the benefit of a utility's ADIT is viewed as a source of zero-cost capital to the utility as part of the ratemaking process. That is, a positive ADIT account reflects the income taxes that customers prepay during the early years of an asset's life. Consequently, the ADIT that results from accelerated tax depreciation is booked as a credit against rate base in the initial years an asset is placed into service, thereby reducing revenue requirements for customers. In the later years of an asset's life, this circumstance reverses, and ADIT can result in an increase in rate base.[39]

Q. Please explain why you are proposing an adjustment to APS's calculation of ADIT.

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[39] This can occur when the depreciation expense included in rates exceeds the depreciation expenses, based on accelerated depreciation, allowed for tax purposes, e.g., when the asset has been fully depreciated for tax purposes but is not yet fully depreciated for book purposes.

A. I believe that APS's recognition of ADIT for the January 1 to June 30, 2017 period is misstated for ratemaking purposes and is therefore unfair to customers. This problem occurs both for post-test year plant and test year plant, i.e., plant-in-service on December 31, 2015. Specifically, rather than recognize that approximately half of the ADIT that will accumulate during 2017 will occur during the first six months of the year, APS apportions to these months various and inconsistent amounts of ADIT, which APS justifies based on the proportion of APS's forecast pretax operating income for January 1 to June 30, 2017 compared to the 2017 annual pretax operating income.[40] In other words, because APS attributes a disproportionately low share of its calendar year income to the first six months of the year, APS scales back the ADIT it recognizes when ADIT is a credit to rate base and inflates the ADIT it recognizes when ADIT is an increase to rate base, for the January 1 to June 30, 2017 period. I believe this approach causes an unreasonable mismatch between plant recognized in rate base and ADIT recognized in rate base, to the disadvantage of customers.

Q. How does APS calculate the ADIT accumulated during the January 1 to June 30, 2017 period related to its post-test year plant additions?

A. APS subtracts its estimated book depreciation for the January 1 to June 30, 2017 period related to its post-test year plant additions from the 2017 annual tax depreciation expense for these assets. APS then multiplies the difference by its federal and state tax rates, and then multiplies this product by 28.45% to arrive at

[40] APS's Confidential Response to AECC Data Request 3.1, included in Confidential Exhibit KCH-11.

its ADIT estimate.[41] At the time of filing, APS's forecast pretax operating income for January 1 to June 30, 2017 was 28.45% of the 2017 annual total, so APS apportioned the ADIT attributable to the January 1 to June 30, 2017 period using this proportion.[42]

Q. Do you believe that recognizing only 28.45% of the 2017 post-test year plant ADIT is appropriate for ratemaking purposes?

A. No. I do not believe this approach is appropriate for ratemaking purposes. It is unreasonable for APS to be trying to obtain full credit in rate base for its post-test year plant, while simultaneously "watering down" the amount of ADIT it recognizes as a credit to rate base. Instead, I recommend that APS's estimated book depreciation expense for the January 1 to June 30, 2017 period be subtracted from <u>50%</u> of the Company's 2017 annual tax depreciation expense for the post-test year plant additions, to properly reflect the 50% share of the calendar year that this period represents. Then the difference should be multiplied by the federal and state tax rates to arrive at the ADIT accumulated during the first six months of 2017 for the post-test year plant additions. My recommended approach will apportion half of the 2017 annual tax depreciation to the January 1 - June 30, 2017 period, and thus will reflect approximately half of the post-test year plant ADIT that will accumulate during 2017 in rates.

Q. Please explain why APS's approach to ADIT is also unreasonable for *test year* plant (i.e., plant in service on December 31, 2015).

[41] EAB_WP07DR RB Pro Forma Post Test Year Plant Additions, "PTYP ADIT (18 Mo) - FED" and "PTYP ADIT (18 Mo) - ST" tabs.
[42] APS's Response to AECC Data Request 7.1, included in Exhibit KCH-1.

A. As foundational matter, it is important to recognize that for test year plant, net book depreciation expense exceeds net tax depreciation expense. Consequently, for test period plant, unlike new plant, the impact on ADIT causes an *increase* to rate base.

For the period January 1, 2016 through June 30, 2017, APS depreciates its existing plant for the purpose of setting rates in this case. Since APS is also seeking recognition of post-test year plant, depreciating the existing (test year) plant is reasonable because this accumulated depreciation appropriately reduces the existing plant rate base to match the time period of the requested plant additions.

The problem occurs in the attribution of ADIT.

Q. How does APS calculate the ADIT accumulated during the January 1, 2016 to June 30, 2017 period related to its test year plant balance as of December 31, 2015?

A. APS estimates 18 months of incremental accumulated book depreciation on its test year plant by multiplying the annual depreciation expense, as updated by APS's new depreciation study, by 1.5. That is, the calculation of book depreciation is proportionate to the measurement period, which I agree is reasonable. In contrast, however, APS estimates the tax depreciation expense incurred during the January 1, 2016 to June 30, 2017 period by adding the 2016 tax depreciation expense to only 28.45% of the 2017 tax depreciation expense.[43] In other words, the time-period weighting of book depreciation and tax

[43] Derived from APS's Response to AECC Data Request 9.3, which is included in Exhibit KCH-1, and EAB_WP07DR RB Pro Forma Post Test Year Plant Additions, "Study Rates (18 months)" tab.

depreciation is mismatched. APS then subtracts the incremental accumulated book depreciation from its estimated incremental accumulated tax depreciation, and multiplies the difference by its federal and state tax rates to calculate ADIT. This calculation results in a net *decrease* in the deferred tax liability associated with test year plant for the January 1, 2016 to June 30, 2017 period because net book depreciation expense exceeds net tax depreciation expense. In other words, recognition of incremental ADIT on existing plant causes rate base to increase. Directionally this is correct, but the *amount* of the rate base increase is overstated by APS because APS only recognizes 28.45% of the 2017 tax depreciation in this calculation.

Q. Do you believe that recognizing only 28.45% of the 2017 tax depreciation is an appropriate method for calculating ADIT on test year plant for ratemaking purposes?

A. No. Consistent with my position regarding post-test year plant, I recommend apportioning <u>50%</u> of the projected 2017 tax depreciation for test year plant to the January 1 to June 30, 2017 period, rather than just 28.45%. Since the January 1 to June 30 period represents half of the year, it is appropriate to recognize half of the 2017 annual tax depreciation in this calculation. In this manner, half of the ADIT that will accumulate during 2017 will be reflected in rates, whereas the Company's method will reflect a disproportionately large impact on 2017 ADIT for test year plant. Since APS's calculation compares approximately 28.45% of 2017 tax depreciation to six months of book depreciation, the difference between tax depreciation and book depreciation for test year plant is *overstated* under APS's method.

In summary, APS's disproportionate attribution of ADIT to the January 1 to June 30, 2017 period causes an *understatement* of ADIT when ADIT is a *benefit* to customers (i.e., when calculating ADIT for post-test year plant) and an *overstatement* of ADIT when ADIT *increases rates* for customers (i.e., when calculating ADIT for test year plant for the January 1, 2016 to June 30, 2017 period). APS's approach produces a "worst of both worlds" outcome for customers and should be rejected.

My adjustment to ADIT is presented in Exhibit KCH-9.[44] I estimate that it reduces APS's ACC jurisdictional revenue requirement by **$3.890** million relative to APS's filed case.

Return on Equity

Q. What return on equity is APS proposing?

A. APS is proposing a return on equity ("ROE") of 10.5%.[45] This return represents an increase of 50 basis points over the 10.00% ROE approved in Decision No. 73183, issued May 24, 2012, in Docket No. E-01345A-11-0224.

Q. Does AECC support APS's request?

A. No. Please refer to Exhibit KCH-10, page 1, which shows the ROEs for vertically-integrated electric utilities approved in the United States from January 1, 2011 through December 31, 2011, as reported by SNL Financial. Page 2 of this exhibit shows the ROEs for vertically-integrated electric utilities approved in the

[44] My ADIT adjustment is based on end-of-period (June 30, 2017) values, consistent with APS's treatment of post-test year plant.
[45] *See* Direct Testimony of Barbara Lockwood, p. 4.

country during 2015 and page 3 shows this same information for the first 11 months of 2016, also as reported by SNL Financial.

The median ROE for this group was 10.19% in 2011, the year in which the last APS rate case was conducted.[46] The 10.00% ROE that APS was awarded in the last general rate case was 19 basis points below that median. Authorized ROEs in the electric utility industry have *fallen* since that time. During 2015, the median approved ROE for vertically-integrated electric utilities was 9.70% and for the first 11 months of 2016, the median approved ROE for vertically-integrated electric utilities was 9.78%. Thus, APS's proposed ROE of 10.50% is moving in exactly the opposite direction of the trend nationally. If APS's ROE were to be reset at a rate reflective of the national median, it would be in the vicinity of 9.75%.

Q. If APS's allowed ROE were to be set at the national median of approximately 9.75%, how would APS's effective return be impacted by the fair value increment?

A. Unlike the vast majority of utilities in the country, the fair value increment provides Arizona utilities with a premium return above the nominal ROE applied to original cost rate base. Thus, even if APS's nominal ROE were to remain in line with the national median, APS's effective ROE would actually be somewhat higher, due to the fair value increment.

[46] APS filed its Application in that case on June 1, 2011 and the Stipulation in that case was filed on January 6, 2012. The Final Commission order was issued May 24, 2012.

Q. In offering the preceding discussion of national trends, are you intending to supplant the Commission's consideration of traditional cost-of-capital analysis?

A. No. I fully expect that Staff, and likely RUCO, will file cost-of-capital analyses for the Commission's consideration, along with that filed by APS. My discussion of national trends is intended to supplement that analysis.

Q. What would be the revenue requirement impact if APS's ROE were set at 9.75%?

A. The revenue requirement impact of setting APS's allowed ROE equal to 9.75% reduces APS's ACC jurisdictional revenue requirement by approximately **$45.736** million relative to APS's filed case. This impact is included in my presentation of AECC's recommended revenue requirement in Exhibit KCH-3, page 1. I have incorporated an ROE of 9.75% into AECC's overall revenue requirement recommendations at this time, pending further information being presented into the record by other parties.

IV. <u>SPECIAL RATEMAKING TREATMENT FOR OCOTILLO EXPANSION AND FOUR CORNERS SCRs</u>

Q. Please describe the special ratemaking treatment that APS is requesting for its Ocotillo modernization and expansion project.

A. As discussed in the direct testimony of Leland R. Snook, APS expects to place into service a modernized and expanded Ocotillo Generating Facility in the spring of 2019. APS plans to retire 220 MW of existing steam generation and replace it with 510 MW of combustion turbine generation.[47]

APS is requesting that the Commission grant an accounting order that will authorize the Company to defer and capitalize for future recovery through rates all costs of owning, operating, and maintaining the new Ocotillo facility, as well as all costs of retiring the existing steam generation.[48] In other words, rather than recover these costs on a going-forward basis by filing a rate case that is timed to coincide with the new plant going into service, as would occur under conventional ratemaking, APS is seeking to defer, or accrue, the costs as they are incurred for later recovery. Mr. Snook estimates that about $45 million of Ocotillo-related deferrals will accrue through 2019, which APS proposes to amortize over five years.[49]

Q. Please describe the special ratemaking treatment that APS is requesting for its Four Corners SCRs project.

A. Mr. Snook testifies that APS must install two SCRs at its Four Corners Generating Facility to comply with federal environmental standards. Mr. Snook explains that APS must install and begin operating the first SCR by March 31, 2018 and the second by July 31, 2018.

APS requests that it be allowed to defer its costs for this project from the time the SCRs are placed into service until December 2018; further, APS asks that it be allowed to impose a step rate increase (i.e., a standalone rate increase) in January 2019 to begin recovering the deferred costs, which would be amortized

[47] Direct Testimony of Leland R. Snook, p. 10.
[48] *Id.*, p. 12.
[49] *Id.*, p. 13.

over five years, as well as the going-forward costs of the project. Mr. Snook estimates that the going-forward revenue requirement associated with these projects will be $62 million per year and that the deferred costs would be an additional $30 million, which would be recovered over five years.

Q. What is your assessment of these proposals?

A. I recommend that the extraordinary ratemaking treatment that APS is seeking for both of these projects be rejected. Deferred accounting is an example of single-issue ratemaking. Single-issue ratemaking occurs when utility rates are adjusted, or costs are deferred, in response to a change in a cost item considered in *isolation*. Single-issue ratemaking ignores the multitude of other factors that otherwise influence rates or recoverable costs, some of which could, if properly considered, move rates in the opposite direction from the single-issue change.

When regulatory commissions determine the appropriateness of a rate or charge that a utility seeks to impose on its customers the standard practice is to review and consider all relevant factors, rather than just certain factors in isolation. Considering some costs in isolation might cause a commission to allow a utility to increase rates, or defer specific costs, to address higher costs in one area without recognizing counterbalancing savings in another area. For example, the proposed deferrals would allow APS to earn a return on its new investment and charge customers for depreciation expenses associated with the new investment without recognizing that the Company's existing rate base would have depreciated to a lower value by that time. Consider also that it is possible for corporate tax rates to be reduced in the U.S. in the next year or two, given the stated policy objectives of the new administration. APS's proposed rates in this case were developed to have customers pay for APS's income tax obligations at current federal tax rates; customers' power rates would be overstated if corporate tax rates are reduced prior to the filing of a new rate case. These are just two examples of the kind of potential cost savings that could offset increases in the specific cost items that APS is proposing to isolate and defer.

The upshot is that single-issue ratemaking is generally not recommended except in extraordinary circumstances. The Commission should view APS's single-issue ratemaking proposals with great wariness. My recommendation is to reject them.

Q. Mr. Snook cites several instances in which deferred accounting has been permitted by the Commission in the past. Do these examples demonstrate that deferred accounting is a generally reasonable approach to deal with recovering the costs of new investment?

A. No. The examples cited by Mr. Snook show that these instances have been relatively few and far between.

Q. Besides the problem of single-issue ratemaking, do you have additional reasons for opposing the special ratemaking treatment that APS is requesting?

A. Yes. In the case of the Ocotillo project, I find it troubling that APS is seeking deferral of the costs of this power plant expansion while simultaneously proposing to eliminate the continuation of the AG-1 buy-through program. Instead of eliminating the buy-through program, APS should be enlisting buy-through customers to opt-out of the APS generation system on a permanent or long-term basis, thereby avoiding the need for additional generating capacity.

APS witness James Wilde indicates that APS requires 3,500 MW of new generating capacity by 2022,[50] yet APS is making no attempt to integrate or plan for the role that opt-out customers could play in deferring the need for part of that new capacity. Indeed, APS is proposing to move in the opposite direction by eliminating its current buy-through pilot program, despite strong customer interest in retaining it.

Q. How would making the AG-1 program a permanent opt-out impact APS's future additions to rate base?

A. One of the criticisms leveled at buy-through programs such as AG-1 is that the utility still incurs fixed generation costs to serve the departed customers. However, with the knowledge that customers in the program have permanently opted out of APS's generation, the Company could treat the departed load as a generation resource for planning purposes. This would allow APS to *avoid* incurring certain new fixed generation costs. Yet, in its discussion of its future generation resource needs, APS acts as if the opt-out resource does not exist. In my rate design testimony, I will present an option for redesigning the buy-through program so that it can be turned into a long-term resource option for APS, for the benefit of customers and the Arizona economy. In the meantime, APS's request for extraordinary ratemaking treatment for its Ocotillo project should be denied.

Q. Do you have any comments regarding the step rate increase proposed by APS for the Four Corners SCR?

A. Yes. This special ratemaking treatment should also be denied as it too is a variant of unwarranted single-issue ratemaking. However, if the Commission

[50] Direct Testimony of James C. Wilde, p. 9.

were to adopt a variant of the step increase, then it is important that the deferred accounting request be denied. If the Commission accedes to APS's request for a single-issue rate increase, then it would be unreasonable and excessive to *also* allow the Company to build up a cost deferral claim prior to the date of the step increase.

V. RESTORING THE SHARING PROVISION IN THE PSA

Q. Please describe the sharing provision that had been previously included in the PSA.

A. APS's Base Fuel Rate is established in a general rate case. The PSA is a mechanism by which deviations from the Base Fuel Rate are either recovered from or credited to customers in between rate cases. Prior to APS's last general rate case, for most PSA items, 90 percent of the deviation was allocated to customers and 10 percent was allocated to APS. The 90/10 sharing provision had been part of the PSA since the PSA was adopted in 2005. The adoption of the PSA was pursuant to a Settlement Agreement (to which AECC was a party) that was approved, with modifications, by the Commission in Decision No. 67744.

Q. What occurred in the last general rate case with respect to the 90/10 sharing provision in the PSA?

A. Although the 90/10 sharing mechanism had been an integral part of the PSA when it was negotiated and included in the 2005 settlement agreement, in the last general rate case APS proposed that it be eliminated. On behalf of AECC, I opposed the elimination of this provision because doing so removes a powerful incentive for the Company to manage its power cost as efficiently as possible and places 100 percent of the risk from deviations in power supply costs on customers. However, the elimination of the sharing mechanism was part of the package that parties to the case, including AECC, agreed to in negotiating the 2012 settlement agreement that was approved by the Commission in the last general rate case.

Q. If the sharing mechanism is so important, why did AECC agree to eliminate it in the last case?

A. Settlement agreements are package deals. The 2012 settlement agreement provided significant benefits for customers, including a zero base rate increase, a significant stay-out period during which APS agreed not to seek a base rate increase, and the establishment of the Experimental AG-1 pilot program, which allows participating customers greater control over managing their power costs and gives them the ability to accept market risks consistent with their corporate preferences. In light of the significant customer benefits included in that package, AECC agreed to accept the elimination of the sharing mechanism. However, the customer benefits provided in the 2012 settlement agreement are not present in the instant APS filing. Net rates are proposed to increase by at least $165.9 million and the AG-1 program is proposed to be eliminated. Just as APS was not required to continue to support the sharing mechanism that it had initially agreed to in the 2005 settlement agreement, AECC is similarly free to advocate for restoration of the sharing mechanism, which, absent the significant customer benefits incorporated into the 2012 settlement agreement, I believe is in the larger public interest.

Q. Why do you believe a risk-sharing mechanism is an important feature of a fuel adjustor such as the PSA?

A. A risk-sharing mechanism is essential to keep customer and Company interests aligned. Under the current PSA, APS simply passes through 100% of changes in base fuel and purchased power costs in between rate cases to customers. This type of 100 percent cost pass-through seriously reduces a utility's incentive to manage its fuel and purchased power costs as well as it would manage them if it remained exposed to the energy cost risk. It is axiomatic that when a firm stands to gain or lose from its cost management decisions, the pursuit of its economic self-interest gives it a powerful incentive to perform well in managing its costs. I strongly recommend against continuing with a PSA design that fails to incorporate this natural economic incentive.

Q. But aren't energy costs largely outside a utility's control?

A. Absolutely not. The utility's energy costs are completely outside of the control of customers, but not of the utility. Utilities are not mere passive bystanders when it comes to managing power costs. Every hour of every day, utilities need to be managing the dispatch of their systems to achieve minimum costs, subject to the reliability constraints under which they operate. This requires a sophisticated approach to managing utility-owned resources, as well as conducting a large volume of transactions – purchases and sales – throughout the year. The depth and breadth of this around-the-clock dispatch and balancing requirement is so extensive that it is inadvisable for regulators to rely solely on after-the-fact prudence audits to ensure sound utility cost-management performance; rather it is far preferable for the Commission to harness the natural economic self-interest of the company to incentivize the desired behavior of ensuring sound utility cost-management performance.

Q. Are there other aspects of managing fuel and purchased power costs that are important besides optimizing system dispatch?

A. Yes. In addition to hourly dispatch, APS enters into numerous transactions throughout the course of the year that impact its fuel and purchased power costs, such as short- and long-term purchases and sales and fuel procurement. For example, APS made more than 5.4 billion kilowatt-hours of short-term, intermediate-term, and long-term firm sales in 2015, worth more than $156 million, transacted with more than 40 counterparties.[51] In addition, the Company transacted for more than 900 million kilowatt-hours of short-term, intermediate-term, and long-term firm purchases in 2015, valued at more than $41 million, consummated with approximately 40 counterparties.[52] The Company also delivered more than 900 million kilowatt-hours and received nearly 800 million kilowatt-hours through exchanges with 12 counterparties in 2015. It is critical that APS have the proper incentives for these transactions to produce the greatest possible net benefit to customers. This incentive is most efficiently implemented by a regime in which APS shares in the benefits and risks of its decisions.

Q. How else do incentives play a role?

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[51] According to APS's 2015 FERC Form 1 data, as compiled by SNL Financial. Excludes Requirements Service (RQ), Out-of-Period adjustments (AD), and Other service (OS).

[52] According to APS's 2015 FERC Form 1 data, as compiled by SNL Financial. Excludes Requirements Service (RQ), Out-of-Period adjustments (AD), Other service (OS), Service from designated generating units (LU) and AG-1 Contracts.

A. Incentives also play an important role with respect to the Company's own operations. For example, it is important for APS to schedule plant maintenance in a manner that takes into account the impact on power costs. By scheduling outages when replacement power is likely to be less or least expensive, the Company is able to control its power costs. A sharing mechanism gives the Company an economic incentive to take proper account of power costs when scheduling outages. Further, under a sharing mechanism, if the Company experiences forced outages that are more frequent or of greater duration than is reasonably projected in rates, the Company shares in the economic consequences of these events. Likewise, if forced outages are less frequent than had been reasonably projected, the Company shares in the benefit of such superior performance. None of this occurs with a 100% pass-through to customers.

Q. Does APS hedge a portion of its fuel and purchased power costs?

A. Yes. When a utility hedges its fuel and/or purchased power costs, it is effectively locking in the cost of fuel and/or purchased power that is expected to be consumed in the future. APS hedges its fuel and purchased power cost on a rolling three-year forward basis using prescribed target hedge levels by specific dates. To execute these hedges, APS uses a combination of financial and physical natural gas and electricity contracts commonly found in the energy marketplace.[53]

So while it is correct that utilities do not control the market price of natural gas, for example, it is nevertheless the case that a utility's *decisions* in executing its natural gas hedging strategy (e.g., timing, magnitude) have a large influence on

[53] Source: APS's Response to Staff Fuel and Purchased Power Procurement Audit 1.9, included in Exhibit KCH-1.

the cost of gas that it ultimately incurs and the fuel costs that are passed on to customers.

Q. If APS locks in forward fuel prices at prices that later decline, how are these costs treated for ratemaking purposes?

A. In a general rate case, under the current operation of the PSA, if the hedged price exceeds the projected market price, the difference is included as a component of fuel cost for full recovery from customers, subject only to prudency considerations. Conversely, if the hedged price is below the projected market price, this difference is credited against the fuel cost recovered from customers. In between rate cases, these differences are included in the PSA, and passed through 100 percent to customers.

Q. What natural gas hedging costs are included for recovery in this general rate case?

A. In its filed case, APS reports a [redacted].[54] However, in its September update, the Company projects gas hedge [redacted], which constitutes approximately [redacted] of APS's projected $243 million of natural gas costs.[55] These [redacted] are not included in the base fuel rates APS has proposed in this case, but would be passed through to customers 100% through the PSA.

Q. How does your proposal to reintroduce risk sharing in the PSA affect the sharing of risks related to APS's hedging decisions?

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[54] PME_WP19DR 2017 Fuel Expense Detail COMP CONF.

[55] APS's Third Supplemental Response to Staff Data Request 1.13, Competitively Confidential Attachment APSRC01525, page 5 of 8, included in Exhibit KCH-11.

A. Under the current arrangement, there is no risk whatsoever to APS from its hedging decisions: short of a prudency disallowance, 100 percent of the risk from APS's hedging decisions is borne by customers.

But if the sharing mechanism is reinstated, if APS's hedges turn out to cost more than was projected at the time of the general rate case, the Company shares in this cost; similarly, if the Company's hedging decisions prove to reduce fuel costs below what was projected in the general rate case, APS shares in this gain.

Q. Do you believe that the threat of a prudency disallowance is sufficient incentive to fully align utility and customer interests in managing fuel costs in between rate cases?

A. No. In my view, the threat of a finding of imprudence following an after-the-fact audit is not a good substitute for a utility having "skin in the game" when it comes to managing its fuel costs. A finding of imprudence essentially requires a determination that a utility acted <u>unreasonably</u> in its power cost management. In contrast, a risk-sharing mechanism structured such that each and every transaction affects the Company's bottom line, provides an incentive for the Company to get the *best possible deal* from every transaction. Striving to get the best possible deal from every transaction is different from simply not behaving unreasonably. Getting the best possible deal is a more exacting and efficient aspiration. A well-crafted sharing mechanism supports this objective.

Q. Do other utility commissions in the western United States require a sharing mechanism as part of power supply adjustors?

A. Yes. Oregon, Washington, Idaho, Montana and Wyoming have each adopted sharing mechanisms that apply to electric utility power cost adjustors approved in those states.

Q. Please describe the sharing mechanisms used in these other states.

A. In Oregon, the power cost adjustors of both Pacific Power and Portland General Electric are subject to an asymmetrical dead band ranging from negative $15 million to positive $30 million on Oregon jurisdictional basis. The utility absorbs or retains power cost variances within the dead band. Outside the dead band, a 90/10 sharing mechanism applies, with customers absorbing 90% of incremental costs above the dead band and receiving 90% of the benefits below the dead band. Further, recovery through the power cost adjustors is subject to an earnings test, with zero recovery or refund if the utility's actual ROE is within 100 basis points of its authorized level.[56]

In Pacific Power's Washington jurisdiction, the power cost adjustor is subject to a $4 million dead band. Asymmetrical sharing bands apply for net power cost variances between $4 million and $10 million, with 50/50 sharing applying to positive variances (net power cost under-recovery) and 75% customer/25% utility sharing applying to negative variances (net power cost over-recovery). Net power cost variances exceeding $10 million are subject to a symmetrical 90% customer/10% utility sharing provision.[57]

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[56] Pacific Power's Oregon power cost adjustment mechanism was adopted in OR Docket No. UE-246, Order No. 12-493 (December 20, 2012). Portland General Electric's power cost adjustment mechanism was adopted in OR Docket Nos. UE-180/UE-181/UE-184, Order No. 07-015 (January 12, 2007). The current mechanism is described in Portland General Electric's Schedule 126.

[57] WA Dockets UE-140762, *et al.*, Order 09 (May 26, 2015).

The latest version of Puget Sound Energy's power cost adjustor in Washington, effective January 1, 2017, includes a $17 million dead band. For variances between $17 million and $40 million, 50/50 sharing applies to positive variances and 65% customer/35% utility sharing applies to negative variances. For variances exceeding $40 million, 90% customer/10% utility sharing applies.[58]

Rocky Mountain Power's Idaho power cost adjustor contains a 90% customer/10% utility sharing mechanism for most components,[59] and Montana-Dakota Utilities Co.'s power cost adjustor in Montana also contains a 90/10 sharing mechanism.[60]

A 70% customer/30% utility sharing provision was adopted for Rocky Mountain Power's Wyoming power cost adjustor in 2011.[61] In its most recent Wyoming general rate case, Rocky Mountain Power proposed to replace the 70/30 sharing provision with a 100% pass-through to customers. However, the Wyoming commission rejected Rocky Mountain Power's proposal, retaining the 70/30 sharing provision in order to incent the utility to improve its base net power cost forecasts and control net power costs.[62]

Q. In your opinion, does the 70/30 sharing arrangement ordered by the Wyoming commission strike a reasonable balance between utility and customer interests?

A. Yes, it does. This sharing ratio places the substantial majority of responsibility for recovering base fuel cost deviations on customers, but it

[58] WA Dockets UE-130617, *et al.*, Order 11 (August 7, 2015), Attachment A to Settlement Stipulation.
[59] ID Case No. PAC-E-15-09, Order 33440 (December 23, 2015).
[60] Montana-Dakota Utilities Co.'s Fuel and Purchased Power Cost Tracking Adjustment – Rate 58.
[61] WY Docket No. 20000-368-EA-10, Memorandum Opinion, Findings and Order (February 4, 2011).
[62] WY Docket No. 20000-469-ER-15, Memorandum Opinion, Findings of Fact, Decision and Order (December 30, 2015), p. 32.

meaningfully aligns utility and customer interests through shared benefits and costs.

Q. Should this Commission consider adopting the 70/30 sharing provision as utilized in Wyoming?

A. Yes. I encourage the Commission to consider adopting the 70/30 sharing provision that was approved in Wyoming, rather than retaining the current 100/0 approach. At a minimum, I recommend that the Commission restore the 90/10 sharing mechanism that was in effect from 2005 through 2012.

VI. EXPANSION OF THE ENVIRONMENTAL IMPROVEMENT SURCHARGE

Q. What is APS proposing regarding the EIS?

A. As discussed by Mr. Snook, APS is proposing that the Commission expand the EIS in several ways. First, APS proposes to modify the cap that is applied to this surcharge from a maximum kWh charge of $0.00016/kWh to a maximum revenue cap of $10 million "year over year," which implies that the cap would increase by $10 million each year. Currently, the EIS is effectively capped at approximately $5 million per year.[63] Second, APS proposes to be able to carry over into subsequent periods any excess EIS adjustment over the annual cap (plus interest). Third, APS proposes the establishment of a balancing account for the EIS.

Q. What is your assessment of APS's proposed modifications?

[63] Direct Testimony of Barbara D. Lockwood, p. 5.

A. I recommend that APS's proposed changes be rejected. The EIS was initially adopted by the Commission in Decision No. 69663 in Docket No. E-01345A-05-0816 et al., but not without misgivings. In approving the $0.00016/kWh surcharge, the Commission rejected an environmental adjustor mechanism as proposed by APS, stating that "Unfortunately, the method by which APS proposes to seek recovery of those [mandated environmental improvement] costs is unusual and outside the ratemaking process, making it difficult to adopt."[64]

The EIS was readdressed in the 2012 settlement agreement approved by the Commission in the last general rate case. The EIS rate was kept unchanged, but the mechanism was modified to ensure that the funds are only used to recover carrying costs on investment capital directed provided by APS to address environmental mandates.[65] The current version of the EIS was negotiated in response to an Environmental and Reliability Adjustor ("ERA") that was proposed by APS in its filing in that case. On behalf of AECC, I opposed adoption of the ERA as a form of unwarranted single-issue ratemaking, but AECC agreed to the EIS that was negotiated in the 2012 settlement agreement. It is safe to say that the current version of the EIS reflects the structure and size of the surcharge to which parties to the last rate case were willing to accept as part of an overall settlement package.

There is no great regulatory principle under which the EIS exists. Indeed, there are sound regulatory arguments against continuation of this surcharge, as it

[64] *See* Docket No. E-01345A-05-0816 et al., Decision No. 69663 at 86.
[65] *See* Docket No. E-01345A-11-0224, Proposed Settlement Agreement, filed January 6, 2012, Section XI.

is an example of single-issue ratemaking, albeit modest in scale at present. In its current form, it is a product of compromise that allows APS a modicum of rate relief for environmental costs that are incurred in between rate cases. Yet APS continues to use this surcharge as a platform to argue for ways to provide significant – and ever-growing – customer rate increases outside general rate cases, along with a balancing account provision that was rejected by the Commission when the EIS was first adopted. My recommendation to the Commission is that there should be no increase in the dollars eligible for recovery through the EIS, no allowed carry-forwards from one period to the next, and no need for the added complexity of a balancing account.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT KCH-1

Exhibit KCH-1

APS's Non-Confidential Responses
To Parties' Data Requests
Referenced in Testimony & Exhibits

ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION'S FOURTH SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN DOCKET NO. E-01345A-16-0036 AND DOCKET NO. E-01345A-16-0123 OCTOBER 31, 2016

AECC 4.1: Please refer to Ms. Blankenship's direct testimony, page 18, line 17 through page 19, line 2.

a. Please describe the nature of the Amonix and Star Center Patent Rights assets. Please explain how these assets were used and useful in the provision of utility service prior to sale.

b. Please explain the ratemaking treatment utilized for the Amonix and Star Center Patent Rights assets prior to sale.

c. Has the company reflected the Amonix and Star Center Patent Rights sales as a reduction to rate base? If so, please explain how this reduction to rate base has been reflected in the test year (e.g., through a pro forma adjustment or a pre-test year reduction to rate base) and provide the amount of the reduction. If the Amonix and Star Center Patent Rights sales did not result in reductions to rate base, please explain why that is the case.

d. Were the Amonix or Star Center Patent Rights sales addressed in any prior Commission dockets or other public proceedings? If so, please provide the docket and decision numbers of the associated proceedings.

e. Please provide the sale price, date of sale closing, and net book value at the time of closing for the Amonix, Star Center Patent Rights, and Kyrene to Knox Transmission Line assets.

f. Please provide a workpaper, in Excel format with formulas intact, that derives the deferred gains of $12,114,000. This workpaper should separately derive the total gains associated with each asset and calculate APS's proposed deferral of 50% of the total gains. Please also provide the interest rate applicable to the deferral and monthly interest accrued to date.

Response: a. Neither APS nor the Star Center are investments subject to the state prudency standard. APS invested in Amonix in the 1990's. Amonix is a company that manufactures solar power generating equipment. APS received a partial payment for Amonix investment that is to be shared with customers.

Witness: Elizabeth Blankenship

ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION'S
FOURTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-16-0036
AND
DOCKET NO. E-01345A-16-0123
OCTOBER 31, 2016

Response Continued:

The APS Star Center was an innovation center and solar plant where APS worked with manufacturers, universities and government laboratories to develop and test emerging technologies that are applicable to APS's business. The APS Star Center has been an invaluable research center related to advancing solar resources for APS's customers among others. On July 14, 2009, APS filed an application for authorization to sell patent rights and related intellectual property rights. APS has developed two types of tracking systems and has patented the tracking system technologies. APS sought authorization to sell the patent rights to an unaffiliated third party with a significant domestic and international presence with the ability to market this technological development.

b. Amonix costs were expensed as part of the Environmental Portfolio Standard. The patent rights asset was an intangible asset with a book value of zero.

c. Yes, the Amonix and sales of Star Center patent rights are reductions to rate base for $6,162,000 and $1,125,000 respectively. Please see the Regulatory Liabilities schedule on EAB_WP5DR.

d. ACC Decision No. 71629 authorizes the sale of patent rights and orders future ratemaking treatment of this transaction should be determined in future rate cases as appropriate.

e. Amonix: May 2010 Proceeds of $6,162,000
Star Center Patent rights: April 2010 Proceeds of $2,251,000
Kyrene to Knox sale: April 2016 $9,900,000 sale price, $289,000 net book value

f. No interest has been accrued to date for Amonix or Star Center patent rights. The amount of $12,214 of interest (May 2016 through September 2016) has been recorded for Knox-Kyrene sale. See attached APSRC01560 for the calculation.

Witness: Elizabeth Blankenship

	Total Gain	Share	Total
Kyrene-Knox sale	$9,610,830	50%	$ 4,805,415
Kyrene-Knox Accrued Interest (after tax)			21,177
Amonix	6,161,929	100%	6,161,929
Star Center Patent rights sale	$2,250,786	50%	1,125,393
			$ 12,113,914

	Actual Monthly Interest Accrued					
	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Total
Annual Interest Rate 0.61%	$ 2,443	$ 2,443	$ 2,443	$ 2,443	$ 2,443	$12,214
Taxes @ 38.54	941	941	941	941	941	4,707
After tax interest	$ 1,501	$ 1,501	$ 1,501	$ 1,501	$ 1,501	$ 7,507

The interest rate in the established one-year Treasury Constant Maturities rate, effective on the first business day of each year, as published on the Federal Reserve Website.

ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION'S
SIXTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-16-0036
AND
DOCKET NO. E-01345A-16-0123
NOVEMBER 18, 2016

AECC 6.1: Please refer to Ms. Blankenship's workpaper "EAB_WP39DR IS Pro Forma Normalize Cash Incentive." Regarding the cash incentive expense for each year 2013, 2014, and 2015, of $39,079(000), 37,908(000), and 43,178(000), respectively, please provide:

a. The actual expense amount or proportion attributable to each of the following components: APS Performance Component, Business Unit Performance Component, and Individual Performance Component.

b. The actual proportion of the Business Unit Performance Component expense attributable to i.) Shareholder Value or ii.) any other metric related to financial performance (please identify the metric[s]).

c. If applicable, the actual proportion of the Individual Performance Component expense attributable to i.) Shareholder Value or ii.) any other metric related to financial performance (please identify the metric[s]).

Response: a. For the related normalized cash incentive amounts the incentive components are as follows:

	Company Performance	Business Unit Performance	Total
	(dollars in thousands)		
2013	$ 17,043	$ 22,036	$39,079
2014	$ 12,880	$ 25,028	$37,908
2015	$ 17,476	$ 25,702	$43,178

The individual performance component does not change the total pool of incentive dollars. The individual performance component is a modifier, increasing or decreasing, the actual amount an individual will receive based on their performance. The individual performance component is only applicable to performance review (non-union) employees.

b. Each Business Unit Performance plan contains a Shareholder Value component. Depending on the business unit the Shareholder Value components may be based on that business unit's O&M budget and/or capital budget. The performance level of the Shareholder Value metric varies across each business unit. On average, the proportion of the Shareholder Value performance level to the total Business Unit Performance is approximately 28% for 2013, 22% for 2014, and 28% for 2015. Please see Pre-filed 1.47 for business unit plan result for 2014 and 2015. Please see EFCA 12.3 for 2016 plan results.

c. See response to (a) above.

ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION'S SEVENTH SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN DOCKET NO. E-01345A-16-0036 AND DOCKET NO. E-01345A-16-0123 NOVEMBER 22, 2016

AECC 7.1: Please refer to APS's response to AECC Data Request 3.1.

a. Has use of the interim period ADIT allocation method for ratemaking purposes, as described in APS's response, been explicitly challenged in an ACC proceeding by any party or litigated before the Commission in the past? If so, please provide the relevant docket numbers in which this issue has been challenged or litigated, and please cite to any Commission decisions regarding this method.

b. Please explain why APS's forecast pretax operating income at the time of filing for January-June 2017 is only 28.45% of the forecast 2017 annual pretax operating income.

Response:

a. To the best of the company's knowledge, the use of the interim period ADIT allocation method for rate making purposes, as described in APS's response to AECC 3.1, has not been explicitly challenged in an ACC proceeding by any party or litigated before the Commission in the past.

b. As a vertically integrated electric utility in the southwestern United States, a majority of APS's revenues are earned during the summer months, when customer electrical usage is at its highest. However, in contrast, a majority of APS's costs are fixed. As a result, the company's pretax operating income tends to be much lower in pre-summer months and much higher during its summer peak season. Consistent with this expectation, APS's forecasted pretax operating income for January-June 2017 at the time of filing was only 28.45% of the annual total.

Witness: Elizabeth Blankenship

ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION'S EIGHTH SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-16-0036 AND DOCKET NO. E-01345A-16-0123
NOVEMBER 22, 2016

AECC 8.1: Please refer to APS's response to AECC Data Request 4.1.

a. Please confirm that APS is proposing to pass 100% of the Amonix sale proceeds on to customers. If denied, please provide the amount of Amonix sale proceeds that APS is proposing to retain.

b. Please describe what is meant by "partial payment" in APS's response to 4.1(a). Does APS anticipate any additional payment for the Amonix sale?

c. Does the $6,162,000 in Amonix sale proceeds represent the entirety of the Amonix sale proceeds that APS anticipates receiving?

d. Regarding the Amonix costs expensed as part of the Environmental Portfolio Standard, beginning in the first year when ratepayers were subject to these expenses through the last such year, please provide the amount of Amonix costs expensed annually.

e. Do customers currently provide, or have customers historically provided, funding for the APS Star Center through rates? If so, please describe the manner in which this funding has been included in rates, and please provide the amount of Star Center costs included in rates annually, beginning in the first year when ratepayers were subject to these costs through the last such year.

Response:

a. Yes, APS is proposing to pass 100% of the Amonix proceeds to customers.

b. Amonix has repaid APS the investment/loan and related interest. APS does not anticipate any additional payments from Amonix.

c. The Amonix proceeds were not from a sale; but rather a repayment of an investment/loan and related interest. APS does not anticipate any additional payments from Amonix.

d. The annual amount of costs charged to the EPS were:

1997	$ 950,000
1998	$ 2,100,000
1999	$ 601,476
2000	$ 512,949
2001	$ 182,000
2002	$ 434,414
2003	$ 1,327,022
2004	$ 250,000
Total	**$ 6,357,861**

Witness: Elizabeth Blankenship

ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION'S
EIGHTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-16-0036
AND
DOCKET NO. E-01345A-16-0123
NOVEMBER 22, 2016

e. Star Center costs would have been included as general operating costs and are not distinguishable specifically as Star Center except for the following O&M costs:

2007	$12,804
2008	$48,686
2009	$27,637
2010	$ 3,117
2011	$21,403
2012	$ 1,731
2013	$ 2,540
2014	$ 4,331
2015	$14,460

The following capital costs (net book value as of 12/31/2015) are and have been included in rate base:

1988	$ 12,315
1990	$ 5,105
1991	$ 1,299
1992	$ 38,015
1994	$ 7,243
1995	$ 48,594
1999	$129,827
2000	$114,141
2001	$116,914
2004	$ 296
2005	$ 22,267
2006	$ 9,673
2008	$ 44,490
2009	$ 192,565
2011	$ 42,537
2013	$ 58,269
2015	$ 518,205
Total	**$1,361,755**

Witness: Elizabeth Blankenship

ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION'S
NINTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-16-0036
AND
DOCKET NO. E-01345A-16-0123
NOVEMBER 23, 2016

AECC 9.1: Please refer to APS's direct post-test year plant additions workpapers, JRL_WP1DR, JJC_WP1DR, JT_WP1DR , JT_WP2DR, SLD_WP1DR, and SBB_WP1DR. For each individual plant addition listed in these workpapers, please provide, in Excel format, the book depreciation rate proposed by APS, and the applicable tax depreciation rates for the project's first year and second year in service. For each plant addition entry, please provide the Work Order/Funding Project, Operating Unit, and Project Name, as it appears in the cited workpapers, alongside the requested depreciation rates. If multiple depreciation rates are applicable to any projects in a given year, please provide a composite average annual depreciation rate for the project.

Response: The depreciation rates provided in the post-test year plant calculations are composite rates that are applicable to each respective project category (e.g. Distribution, Fossil). This was also done in prior APS rate cases. These rates are available in the depreciation study (Section IV, Statement A). APS is not able to identify the specific accounts of each individual project until the projects are completed and unitized. Therefore, in order to calculate the high-level post-test year plant estimates, the composite rates are utilized to calculate depreciation per project category as a whole. These composite rates, as well as the tax depreciation rates are available on the PTYP ADIT (18 Mo) - Fed and the PTYP ADIT (18 Mo) - ST tabs of workpaper EAB_WP07DR.

Witness: Elizabeth Blankenship

ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION'S NINTH SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN DOCKET NO. E-01345A-16-0036 AND DOCKET NO. E-01345A-16-0123 NOVEMBER 23, 2016

AECC 9.2: Please refer to Ms. Blankenship's workpaper, EAB_WP07DR RB Pro Forma Post Test Year Plant Additions, the PTYP ADIT (18 Mo) – FED tab. Please explain why the Plant Additions (2016) and Plant Additions (2017) as shown on this workpaper do not match the amount of plant additions that are projected to go into service during the corresponding January 1- December 31, 2016 and January 1- June 30, 2017 periods, as presented in the workpapers JRL_WP1DR, JT_WP1DR , JT_WP2DR, and SBB_WP1DR.

For example, according to EAB_WP07DR RB Pro Forma Post Test Year Plant Additions, the PTYP ADIT (18 Mo) - FED tab, $250,102,652 in Distribution plant additions were projected in 2016, and $20,389,637 in 2017. However, as derived from JT_WP1DR, $46,971,873 of Distribution plant additions were projected to go into service between January 1-December 31, 2016 (including trailing costs), and $223,520,340 between January 1-June 30, 2017.

Response: The difference between the two schedules is related to programs included in PTYP. A "program" represents a group of work authorizations/capital projects managed to achieve routine replacements, ongoing improvements, expected emergent work of a consistent nature (like-kind work similar or identical in nature). Work authorization for programs are completed and placed into service throughout the year or program period. For simplicity purposes, APS reflected the in-service date of programs to be 6/30/2017, however as noted above work orders related to programs are placed into service throughout the year or program period.

Witness: Elizabeth Blankenship

ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION'S NINTH SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN DOCKET NO. E-01345A-16-0036 AND DOCKET NO. E-01345A-16-0123 NOVEMBER 23, 2016

AECC 9.3: Please refer to Ms. Blankenship's workpaper, EAB_WP07DR RB Pro Forma Post Test Year Plant Additions, the Study Rates (18 months) tab. For each of the plant categories listed in the Federal and State tax depreciation tables, please provide the annual depreciation expense for tax purposes for tax years 2016 and 2017 applicable to non-post-test year plant.

Response: Please see the table below for the annual depreciation expense for tax purposes for tax years 2016 and 2017 for each of the plant categories listed in the Federal and State tax depreciation tables of the Study Rates (18 months) tab of Ms. Blankenship's workpaper, EAB_WP07DR RB Pro Forma Post Test Year Plant Additions.

Federal	**Tax Year 2016**	**Tax Year 2017**
Distribution	$ 117,789,405	$ 109,242,324
General & intangible	46,348,151	31,567,016
Nuclear	20,712,704	19,835,250
Solar	33,004,129	22,102,157
Gen (non-Nuclear)	67,681,082	63,791,797
Transmission	55,406,482	52,060,127
Total Federal	**$ 340,941,953**	**$ 298,598,672**

State	**Tax Year 2016**	**Tax Year 2017**
Distribution	$ 175,467,146	$ 159,929,827
General & intangible	87,563,318	57,507,314
Nuclear	31,419,954	29,829,890
Solar	88,892,949	52,129,431
Gen (non-Nuclear)	93,521,292	87,433,704
Transmission	89,955,092	84,745,159
Total State	**$ 566,819,751**	**$ 471,575,324**

Witness: Elizabeth Blankenship

ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION'S FIFTEENTH SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN DOCKET NO. E-01345A-16-0036 AND DOCKET NO. E-01345A-16-0123 DECEMBER 14, 2016

AECC 15.1: Please refer to APS's Fifth Supplemental Response (December 9th) to Staff Data Request 1.13, regarding the cash incentive proforma. For each year 2013 through 2015, please provide the total proportion of cash incentive expense allocated from Pinnacle West to APS attributable to financial performance (i.e. APS financial performance, Pinnacle West financial performance, shareholder value, or any other financial performance metric.)

Response: The total portion of normalized cash incentive expense allocated from Pinnacle West to APS attributable to Company Earnings Performance is $1,392,401 for 2013, $920,705 for 2014, and $919,705 for 2015. Please note amounts are shown as normalized expense amount which are stated in 2015 dollars.

Witness: Elizabeth Blankenship

ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION'S FIFTEENTH SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-16-0036
AND
DOCKET NO. E-01345A-16-0123
DECEMBER 14, 2016

AECC 15.5: Please refer to Schedule C-2. Please provide a workpaper in Excel format that shows the derivation of the ACC jurisdictional portion of the depreciation and amortization expense adjustments for Distribution and IT/Facilities Post-Test Year Plant Additions, Customer Service Post-Test Year Plant Additions, and Renewables, Microgrid & Technology Innovation Post-Test Year Plant Additions. This workpaper should separately itemize the components of APS's adjustments (e.g., Distribution, General, Intangible, Modern Grid-Distribution, Modern Grid-Meters, and any other component), and should provide the name of the applicable jurisdictional allocator and jurisdictional allocator percentage alongside each adjustment component.

Response: Please see attachment APSRC01783 for an Excel workpaper which calculates the ACC jurisdictional amounts for the Post-Test Year Plant pro formas. Please see witness Leland Snook's workpaper LRS_WP02DR for a summary of functionalization and allocation factor for each pro forma in SFR Schedule C-2.

Response to AECC 15.5
ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustment
Test Year Ended 12/31/2015
(Dollars in Thousands)
Total Co.

Line No.	Description		Fossil Post-Test Year Plant Additions	Nuclear Post-Test Year Plant Additions	Distribution Post-Test Year Plant Additions	IT/Facilities Post-Test Year Plant Additions
	Electric Operating Revenues					
1.	Revenues from Base Rates		$ -	$ -	$ -	$ -
2.	Revenues from Surcharges		-	-	-	-
3.	Other Electric Revenues		-	-	-	-
4.	Total Electric Operating Revenues		-	-	-	-
5.	Electric Fuel and Purchased Power Costs		-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-	-	-	-
	Other Operating Expenses:					
7.	Operations Excluding Fuel Expense		-	-	-	-
8.	Maintenance		-	-	-	-
9.	Subtotal		-	-	-	-
10.	Depreciation and Amortization		6,876	2,008	6,627	17,617
11.	Amortization of Gain		-	-	-	-
12.	Administrative and General		-	-	-	-
13.	Other Taxes		1,118	866	5,492	3,928
14.	Total Other Operating Expense		7,994	2,874	12,119	21,545
15.	Operating Income Before Income Tax		(7,994)	(2,874)	(12,119)	(21,545)
16.	Interest Expense	2.27%	(858)	1,092	760	953
17.	Taxable Income		(7,136)	(3,966)	(12,879)	(22,498)
18.	Current Income Tax Rate	38.10%	(2,719)	(1,511)	(4,907)	(8,572)
19.	Operating Income (line 15 minus line 18)		$ (5,275)	$ (1,363)	$ (7,212)	$ (12,973)

Distribution and IT/Facilities Plant Additions Total
$ (20,185)

Adjustment to Test Year operations to include depreciation, interest expense, property taxes and reduced income tax expense associated with Fossil, Nuclear, Distribution and IT/Facilities, Customer Service, Renewables, Microgrid and Technology Innovation Post-Test Year Plant Additions.

Response to AECC 15.5
ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustment
Test Year Ended 12/31/2015
(Dollars in Thousands)
Total Co.

Line No.	Description	Customer Service Post-Test Year Plant Additions	Renewables, Microgrid & Technology Innovation Post-Test Year Plant Additions	Technology Innovation Post-Test Year Plant Additions	Total Company Post-Test Year Plant Additions
	Electric Operating Revenues				
1.	Revenues from Base Rates	$ -	$ 2,511	$ -	$ 2,511
2.	Revenues from Surcharges	-	-	-	-
3.	Other Electric Revenues	-	-	-	-
4.	Total Electric Operating Revenues	-	2,511	-	2,511
5.	Electric Fuel and Purchased Power Costs	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	2,511	-	2,511
	Other Operating Expenses:				
7.	Operations Excluding Fuel Expense	-	-	-	-
8.	Maintenance	-	-	-	-
9.	Subtotal	-	-	-	-
10.	Depreciation and Amortization	12,048	6,051	2,864	54,091
11.	Amortization of Gain	-	-	-	-
12.	Administrative and General	-	-	-	-
13.	Other Taxes	2,353	644	1,651	16,052
14.	Total Other Operating Expense	14,401	6,695	4,515	70,143
15.	Operating Income Before Income Tax	(14,401)	(4,184)	(4,515)	(67,632)
16.	Interest Expense	2,452	831	1,469	6,699
17.	Taxable Income	(16,853)	(5,015)	(5,984)	(74,331)
18.	Current Income Tax Rate	(6,421)	(1,911)	(2,280)	(28,320)
19.	Operating Income (line 15 minus line 18)	$ (7,980)	$ (2,273)	$ (2,235)	$ (39,312)

Renewables, Microgrid and Technology Innovation Post Test Year Plant Additions Total
$ (4,508)

Response to AECC 15.5
ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustment
Test Year Ended 12/31/2015
(Dollars in Thousands)
ACC

Line No.	Description		Fossil Post-Test Year Plant Additions	Nuclear Post-Test Year Plant Additions	Distribution Post-Test Year Plant Additions	IT/Facilities Post-Test Year Plant Additions
	Electric Operating Revenues					
1.	Revenues from Base Rates		$ -	$ -	$ -	$ -
2.	Revenues from Surcharges		-	-	-	-
3.	Other Electric Revenues		-	-	-	-
4.	Total Electric Operating Revenues		-	-	-	-
5.	Electric Fuel and Purchased Power Costs		-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-	-	-	-
	Other Operating Expenses:					
7.	Operations Excluding Fuel Expense		-	-	-	-
8.	Maintenance		-	-	-	-
9.	Subtotal		-	-	-	-
10.	Depreciation and Amortization		6,839	1,997	6,625	16,279
11.	Amortization of Gain		-	-	-	-
12.	Administrative and General		-	-	-	-
13.	Other Taxes		1,112	861	5,490	3,630
14.	Total Other Operating Expense		7,951	2,858	12,115	19,908
15.	Operating Income Before Income Tax		(7,951)	(2,858)	(12,115)	(19,908)
16.	Interest Expense	2.27%	(853)	1,086	760	881
17.	Taxable Income		(7,097)	(3,945)	(12,874)	(20,789)
18.	Current Income Tax Rate	38.10%	(2,704)	(1,503)	(4,905)	(7,921)
19.	Operating Income (line 15 minus line 18)		$ (5,247)	$ (1,355)	$ (7,210)	$ (11,987)

Distribution and IT/Facilities Plant Additions Total
$ (19,197)

Adjustment to Test Year operations to include depreciation, interest expense, property taxes and reduced income tax expense associated with Fossil, Nuclear, Distribution and IT/Facilities, Customer Service, Renewables, Microgrid and Technology Innovation Post-Test Year Plant Additions.

Response to AECC 15.5
ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustment
Test Year Ended 12/31/2015
(Dollars in Thousands)
ACC

Line No.	Description	Customer Service Post-Test Year Plant Additions	Renewables, Microgrid & Technology Innovation Post-Test Year Plant Additions	Technology Innovation Post-Test Year Plant Additions	Total Company Post-Test Year Plant Additions
	Electric Operating Revenues				
1.	Revenues from Base Rates	$ -	$ 2,511	$ -	$ 2,511
2.	Revenues from Surcharges	-	-	-	-
3.	Other Electric Revenues	-	-	-	-
4.	Total Electric Operating Revenues	-	2,511	-	2,511
5.	Electric Fuel and Purchased Power Costs	-	-	-	-
6.	Oper Rev Less Fuel & Purch Pwr Costs	-	2,511	-	2,511
	Other Operating Expenses:				
7.	Operations Excluding Fuel Expense	-	-	-	-
8.	Maintenance	-	-	-	-
9.	Subtotal	-	-	-	-
10.	Depreciation and Amortization	11,133	6,051	2,863	51,786
11.	Amortization of Gain	-	-	-	-
12.	Administrative and General	-	-	-	-
13.	Other Taxes	2,174	645	1,650	15,563
14.	Total Other Operating Expense	13,307	6,696	4,513	67,349
15.	Operating Income Before Income Tax	(13,307)	(4,185)	(4,513)	(64,838)
16.	Interest Expense	2,266	832	1,468	6,439
17.	Taxable Income	(15,573)	(5,017)	(5,982)	(71,277)
18.	Current Income Tax Rate	(5,933)	(1,911)	(2,279)	(27,157)
19.	Operating Income (line 15 minus line 18)	$ (7,374)	$ (2,274)	$ (2,234)	$ (37,681)

Renewables, Microgrid and Technology Innovation Post Test Year Plant Additions Total
$ (4,508)

ARIZONA PUBLIC SERVICE COMPANY
Post-Test Year Plant Additions (18-Months)
Property Taxes and Depreciation
(Dollars in Thousands)

Description	Plant Additions	Depreciation Rate	Depreciation Expense	Full Cash Value	Assessed Value 18%	Property Taxes 11.42%
Distribution	**270,492**	**2.45%**	**6,627**	**267,179**	**48,092**	**5,492**
General	62,438	6.20%	3,871	60,502	10,890	1,244
Intangible	137,457	10.00%	13,746	130,584	23,505	2,684
Total General & Intangibles	**199,894**		**17,617**	**191,086**	**34,395**	**3,928**
Nuclear Production	**123,961**	**1.62%**	**2,008**	**42,147**	**7,586**	**866**
Renewables	**156,754**	**3.86%**	**6,051**	**31,351**	**5,643**	**644**
Modern Grid - Distribution	47,983	2.45%	1,176	47,395	8,531	974
Modern Grid - Meters	33,772	5.00%	1,689	32,927	5,927	677
Total Modern Grid	**81,755**		**2,864**	**80,322**	**14,458**	**1,651**
Customer Service	**120,485**	**10.00%**	**12,048**	**114,460**	**20,603**	**2,353**
Steam Production	108,740	4.50%	4,893	36,972	6,655	760
Other Production	51,895	3.82%	1,982	17,437	3,139	358
Total Fossil	**160,635**		**6,876**	**54,408**	**9,794**	**1,118**
Total PTYP Additions	**1,113,976**		**54,091**	**780,953**	**140,572**	**16,052**

ACC Jurisdictional Percentages
(rounded values)

Wages & Salaries	ACC %
Total Company	92.4042%
Total Company wo/Transmission	99.5479%
Production	99.4293%
Transmission	0.0000%
Distribution	99.6719%
Customer Accounts	99.8722%
Customer Service	100.0000%
Sales	99.8722%

PT&D	ACC %
Total Company	83.7503%
Total Company wo/Transmission	99.6768%
Production-PT & D	99.4600%
Transmission-PT & D	0.0000%
Distribution-PT & D	99.9639%

PT&D Less Land	ACC %
Total Company	84.5023%
Total Company wo/Transmission	96.4600%
Production less Land	96.4600%
Transmission less Land	0.0000%
Distribution less Land	99.9635%

Note: Leland Snook sponsors this information.

ARIZONA CORPORATION COMMISSION'S FIRST SET OF DATA REQUESTS TO ARIZONA PUBLIC SERVICE COMPANY REGARDING THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN DOCKET NO. E-01345A-16-0036 JULY 28, 2016

Staff 1.13: Errors. As the Company discovers errors in its filing, identify such errors and provide documentation to support any changes. Please update this response as additional information becomes available.

Response: **Errors found as of August 8, 2016:**

Company will provide the requested documentation in the event an error is identified. In addition, consistent with past practice, the Company will update critical estimates throughout the process. The estimates made that will be updated include property tax expense, the amount of the AG-1 deferral, the amount of the property tax deferral, base fuel estimates, and the post-Test Year plant pro formas, among others. APS has committed to provide the updated information to all parties using 9/30/2016 information to be provided no later than 10/31/2016.

To date, APS filed two erratas for items related to the E-5 (Witness Elizabeth Blankenship) and the H-5 (Witness Charles Miessner). Neither of which had any substantive effect on the filing.

In addition, APS has found one other minor error:

- On the pro forma titled "Test Year PSA Revenue and Deferred Fuel Amortization" the Test Year amount on Line 4 of Pete Ewen Attachment PME-05DR titled "PSA SO2 Margin Deferral Amortization" showed ($25,000) and it should have been $25,000. This correction results in an Operating Income Before Tax of $0. Attached as APSRC00772 is the revised pro forma adjustment (Witness Pete Ewen).

Supplemental Response: **Errors found as of September 19, 2016:**

APS inadvertently provided a redline of E-4 using an old tariff sheet referenced in APS's response to AURA 1.34. The clean version of the E-4 schedule was correct.

Ahmad Faruqui had an incorrect number stated in his testimony. Correcting this number does not change anything else in his testimony. See APS's response to AURA 1.11 for details.

Second Supplemental Response: **Errors found as of October 26, 2016:**

After further review APS did find a math error that will be corrected when we provide a revised Cash Working Capital document at the next technical conference. The effect of the math error changes the total Working Capital Requirement for Wheeling from $995,702 to

Witness: Depending upon subject matters

ARIZONA CORPORATION COMMISSION'S
FIRST SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-16-0036
JULY 28, 2016

$1,228,084. See APS's response to Staff 7.2 for further details.

Miessner Workpaper CAM_WP01DR contained a mathematical error concerning a transfer of billing determinants for the two customers that is corrected in attachment APSRC01414. This correction does not change the requested revenue from the extra-large customer classes. However, it does change the proposed charges for rates E-34, E-35 and XHLF. See APS's response to Staff 10.3 for further details.

APS also noticed that in the calculation of the base water costs to be used in the calculation of the annual PSA rate, the total Palo Verde number was used instead of the APS only share of Palo Verde's water costs. APS will update this value in its Rebuttal testimony. See APS's response to Staff 8.18 for more information on APS's share of Palo Verde water costs.

Third Supplemental Response:

Updates on November 1, 2016:

Updated Revenue Requirement

Per APS's initial response to this question, the Company is providing updates to pro forma estimates as of 9/30/2016. APS will present the results of this information at the Technical Conference on November 3, 2016. Please note the updated numbers are higher than what was filed on June 1, 2016, but APS is not proposing any change to its original request.

See table below for information provided:

Item	Bates
SFRs Updates	
A-1-Tech Conference	APSRC01491
B-1-Tech Conference	APSRC01492
B-2-Tech Conference	APSRC01493
B-3-Tech Conference	APSRC01494
C-1-Tech Conference	APSRC01495
C-2-Tech Conference	APSRC01496
Pro Forma Updates	
EAB_WP7TC - Detail of Pro forma Adjustment: Post Test Year Plant Additions (Rate Base)	APSRC01497
EAB_WP9TC - Details of Pro forma Adjustment: Include Property Tax Deferral	APSRC01498
EAB_WP10TC - Details of Pro forma	APSRC01499

ARIZONA CORPORATION COMMISSION'S
FIRST SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
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Adjustment: Adjust Cash Working Capital for Cost of Service (Rate Base)	
EAB_WP19TC - Detail of Pro forma Adjustment: Office Closure and Paystation Fee Socialization (Income Statement)	APSRC01500
EAB_WP33TC - Detail of Pro forma Adjustment: Adjustment for Post-Test Year Plant Additions (Income Statement)	APSRC01501
EAB_WP41TC - Detail of Pro forma Adjustment: Annualize Property Tax Expense (Income Statement)	APSRC01502
EAB_WP42TC - Detail of Pro forma Adjustment: Amortize Property Tax Deferral (Income Statement)	APSRC01503
EAB_WP45TC - Detail of Pro forma Adjustment: Adjust Cash Working Capital for Cost of Service Pro Formas (Income Statement)	APSRC01504
CAM_WP06TC - IS - Include Amortization of AG-1 Deferral Pro Forma	APSRC01505
CAM_WP07TC - RB - Include AG-1 Deferral Pro Forma	APSRC01506
CAM_WP11TC - IS - Limited Income Discount (E-3,E-4)	APSRC01507
JRL_WP1TC - Fossil Post-Test Year Plant Additions	APSRC01508
JJC_WP1TC - Nuclear Post-Test Year Plant Additions	APSRC01509
JT_WP1TC - Distribution Post-Test Year Plant Additions	APSRC01510
JT_WP2TC - IT and Facilities Post-Test Year Plant Additions	APSRC01511
SLD_WP1TC - Customer Service Post-Test Year Plant Additions	APSRC01512
SBB_WP1TC - Renewables, Microgrid and Technology Innovation Post-Test Year Plant Additions	APSRC01513
Attachment PME-1TC - Summary of Base Fuel Cost Changes	APSRC01514
Attachment PME-3TC - Base Fuel and Purchased Power Pro Forma	APSRC01515
Attachment PME-4TC - Components of Current and Proposed Base Fuel Rates	APSRC01516
PME_WP15DR - Summary of Base Fuel Changes	APSRC01517

Witness: Depending upon subject matters

Summary of Base Fuel Cost Changes

	Current Authorized Level (2012 Conditions)	Proposed Proforma Level (2017 Conditions)	Proforma vs. Current Authorized
Base Fuel Cost (¢/kWh)	3.2071	3.1610	(0.0461)
Test Year Period Normalized Sales (GWh)	27,781	27,781	-
Base Fuel Expense ($000,000)	890.9	878.2	**(12.7)**

Reasons for Change ($000,000)	
Prices for Hedged Natural Gas, Purchased Power	(119.3)
Capacity Costs	(40.6)
Nuclear Price	(9.4)
Price of Renewables Purchases	30.1
Higher Share of Natural Gas, Renewables	40.9
Coal Price	77.5
All Other Items	8.1
Total	**(12.7)**

APSRC01515
Attachment PME-3TC
Page 2 of 3

Components of APS Base Fuel Rate
Proposed Rate Using 9/30/16 Market Prices

	Fuel Expense ($000)	Production (GWH)	Native Load Sales (GWH)	Share of Production %	Average Cost Not Weighted (¢/kWh)	Average Cost Weighted (¢/kWh)
Nuclear [1]	70,488	9,290	8,682	30%	0.81	0.2468
Coal [2]	228,154	8,832	8,255	29%	2.76	0.7988
Natural Gas [3]	242,897	8,734	8,162	29%	2.98	0.8504
Purchased Power [4, 5]	130,452	913	853	3%	15.28	0.4567
Renewable [6, 7]	164,607	2,791	2,608	9%	6.31	0.5763
Fixed Gas Transport and Fuel Handling	86,220	-	-	0%		0.3019
Total	922,819	30,560	28,561	100%		3.2310
Off System Margin Credit	(19,993)		28,561			(0.0700)
Net Retail Fuel Cost	902,827		28,561			**3.1610**
Native Load Sales						
Retail Sales			28,561			
Sales for Resale			-			
Pacificorp Supplemental Sales			-			
Total Native Load Sales			28,561			

1 - Excludes fixed ISFSI expense
2 - Excludes coal reclamation costs.
3 - Includes fuel costs associated with long-term tolling arrangements.
4 - Includes native load hedge liquidation costs.
5 - Includes fixed capacity contract costs.
6 - Excludes costs for above market purchase premiums which are recovered through RES.
7 - Includes generation associated with company owned facilities.

ARIZONA PUBLIC SERVICE COMPANY
Detail of Pro Forma Adjustments to Operating Income as Shown on Schedule C-2, page 10, column 28
Total Company
(Thousands of Dollars)

Pro Forma Adjustment: **Base Fuel and Purchased Power**
Adjustment to Test Year Operations to include 2017 base fuel and purchased power ¢/kWh costs at adjusted Test Year consumption

Line No.	Description		Amount
	ADJUSTED TEST YEAR FUEL AND PURCHASED POWER COSTS (¢/kWh)		
1.	Normalized 2017 Fuel and Purchased Power Costs (¢/kWh)	3.1610	
2.	Test Year Fuel and Purchased Power Costs (¢/kWh)	3.1359	
3.	Adjustment to Fuel and Purchased Power Costs (¢/kWh)	0.0251	
	ADJUSTED TEST YEAR RETAIL SALES (MWh)		
4.	Test Year Retail Sales (MWh)	27,950,491	
5.	Pro Forma Adjustments to Test Year Billed Retail Sales (MWh)		
6.	To Adjust to Normal Weather	(284,704)	
7.	To Annualize to December 31, 2015 Customer Level	115,108	
8.	Adjusted Test Year Retail Sales (MWh)	27,780,895	
9.	Pro Forma Adjustment to Fuel and Purchased Power Expenses (Line 3 x Line 8)		$ 6,973
10.	**Operating Income (before income tax)**		**$ (6,973)**
11.	Current Income Tax Rate - 38.87%		(2,710)
12.	**Operating Income After Tax**		**$ (4,263)**

INFORMATIONAL USE ONLY

PME_WP19DR - 2017 Fuel Expense Detail (COMPETITIVELY CONFIDENTIAL)	APSRC01525

Please note some information is competitively confidential and is being provided pursuant to an executed protective agreement.

Error in Staff 12
APS determined the language provided in the filed Flat Bill Rate Schedule was inaccurate and will need to be revised. Please see Staff 12.5 for the proposed 30% threshold language.

Updates on November 7, 2016:

Fourth Supplemental Response:

Staff 13.4b: There was a typo in APS's response to Staff 8.8 sub part "f" regarding jurisdictional ADIT figures related to the OPEB asset. APS corrected the response in Staff 13.7 stating that $168.753 million represents the ACC jurisdictional amount of the OPEB assets. The ACC jurisdictional amount related to OPEB deferred taxes is $65.594 million.

Staff 13.7: The original document provided in response to subpart "a" of Staff Data Request 8.19 (APSRC01370) contained incorrect storm restoration costs. APS provided a supplemental response to Staff 8.19 subpart "a" and new attachment APSRC01529, which corrected the erroneous costs provided in APSRC01370. The costs provided in APSRC01529 match those provided in APSRC01393. APS responds to Staff 13.7 by directing Staff to the supplemental response and attachment found in Staff 8.19.

Staff 14.3: Service Schedule 1 is being corrected to show the Non-Standard Service Request Charge (new Subsection 2.4) is the same as the Non-Standard Connect Charge listed in the Statement of Charges.

Staff 14.12: Service Schedule 1 will be revised to clarify APS is not proposing to apply the set-up fee to customers with existing non-standard metering in place.

Staff 14.14: APS inadvertently omitted the referenced definition in Service Schedule 1. The definitions section will be revised to include the following: "Service Establishment Charge means the charge for setting up a new account".

Witness: Depending upon subject matters

ARIZONA CORPORATION COMMISSION'S
FIRST SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-16-0036
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Updates on December 9, 2016:

Fifth Supplemental Response:	**Normalize Cash Incentive Proforma** APS inadvertently omitted incentive transactions allocated from Pinnacle West to APS. The proforma changed from original proforma of $1,861K to $1,968K (EAB_WP39DR vs Attachment APSRC01735). See attachment APSRC01735 for the updated Proforma.

Witness: Depending upon subject matters

ARIZONA PUBLIC SERVICE COMPANY
Income Statement Pro Forma Adjustments
Test Year Ended 12/31/2015
(Dollars in Thousands)

Line No.	Description		Normalize Cash Incentive
	Electric Operating Revenues		
1.	Revenues from Base Rates		$ -
2.	Revenues from Surcharges		-
3.	Other Electric Revenues		-
4.	Total Electric Operating Revenues		-
5.	Electric Fuel and Purchased Power Costs		-
6.	Oper Rev Less Fuel & Purch Pwr Costs		-
	Other Operating Expenses:		
7.	Operations Excluding Fuel Expense	**EAB_WP38 page 2 [A]**	(2,079)
8.	Maintenance	**EAB_WP38 page 2 [B]**	(50)
9.	Subtotal		(2,129)
10.	Depreciation and Amortization		-
11.	Amortization of Gain		-
12.	Administrative and General	**EAB_WP38 page 2 [C]**	(1,050)
13.	Other Taxes		-
14.	Total Other Operating Expense		(3,179)
15.	Operating Income Before Income Tax		3,179
16.	Interest Expense		-
17.	Taxable Income		3,179
18.	Current Income Tax Rate - 38.10% (Line 15 * 38.1%)		1,211
19.	Operating Income (line 15 minus line 18)		$ 1,968

Adjustment Test Year operations to normalize the cash incentive program over a 3 year period.

ARIZONA PUBLIC SERVICE COMPANY
Test Year Ended 12/31/2015
Pro Forma Summary Detail

	Total Company		
	2013	2014	2015
Account			
500	$ -	$ -	$ -
506	$ 3,493	$ 3,374	$ 4,349
510	$ -	$ -	$ -
512	$ -	$ -	$ -
514	$ -	$ -	$ -
519	$ 844	$ 923	$ 996
524	$ 7,594	$ 8,310	$ 8,956
546	$ 1,149	$ 1,237	$ 14
549	$ -	$ -	$ 2,236
557	$ 801	$ 738	$ 607
566	$ 1,363	$ 1,188	$ 1,634
580	$ 140	$ 12	$ -
586	$ -	$ -	$ 187
588	$ 5,245	$ 4,401	$ 4,175
593	$ -	$ -	$ 69
598	$ -	$ -	$ 168
903	$ 3,034	$ 3,621	$ 3,300
908	$ -	$ -	$ -
916	$ 618	$ 658	$ 873
920	$ 15,053	$ 13,529	$ 15,570
926	$ 225	$ 336	$ 302
928	$ 328	$ 347	$ 552
930.2	$ 1,407	$ 1,085	$ 1,466
	$ 41,294	$ 39,759	$ 45,454
Participant A&G Credit (net APS A&G)	$ (3,749)	$ (3,126)	$ (3,598)
Net O&M Incentive	$ 37,545	$ 36,633	$ 41,856

	Total APS	Operations	Maintenance	A&G
3 Year Average	$ 38,678	24,641	794	13,242
Less 2015 Incentive Amount	$ 41,856	26,720	844	14,292
Adjustment to Incentive	$ (3,178)	(2,079)	(50)	(1,050)
		[A]	[B]	[C]

ARIZONA CORPORATION COMMISSION
STAFF'S FIRST SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE MATTER OF FUEL AND PURCHASED POWER PROCUREMENT
AUDITS FOR ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-16-0123
JULY 14, 2016

Staff 1.9: Please provide discussion of APS use of fuel and purchased power hedging.

Response: APS hedges natural gas and electricity to reduce the exposure of energy price volatility to its customers, which increases rate stability.

The Company's hedging program was introduced in the late 1990's as power market instability evolved. By 2003, APS had adopted formal hedging guidelines that set the proportion of its requirements for gas and purchased power for which prices would be fixed and provided coverage extending three years. The current hedging program has been in place since 2005.

The main elements of the current hedge plan are prescribed target hedge levels by specific dates over a three year rolling term. The commodities included in the plan include natural gas, purchased power and natural gas basis differential. Specific percentage hedge levels must be maintained during this rolling period in order to remain compliant. Compliance is independently measured by the APS Risk Control Management department.

Finally, APS Traders utilize various hedging products to manage the commodity price risk. These traders hedge with a combination of financial and physical natural gas and electricity contracts regularly found in the energy market place. The traders primarily execute transactions on an electronic trading platform, such as the Intercontinental Exchange ("ICE"), or by phone (recorded line).

In addition to the description above, information on the Company's hedging policy can be found in the 2006 Fuel Audit conducted by Liberty Consulting Group on pages 67 and 68. The Company's hedging policies and procedures are provided in response to Staff 1.3.

EXHIBIT KCH-2

APS Updated Fuel & Purchased Power Impact

Income Statement Impact
(Thousands of Dollars)

Pro Forma Impact: **Fuel & Purchased Power Expense**
Impact of APS's Updated 2017 Fuel & Purchased Pro Forma Expense in Test Year Operations Expense

Line No.	Description	APS Total Company Amount	ACC Jurisdictional Allocation Factor	AECC ACC Jurisdictional Amount	Source
1	**Electric Operating Revenues**				
2	Revenues from Base Rates				
3	Revenues from Surcharges				
4	Other Electric Revenues				
5	**Total**	$0		$0	= Sum (Lns. 2:4)
6	**Operating Expenses:**				
7	Electric Fuel and Purchased Power	48,598	100.00%	$48,598	See Page 2
8	Operations and Maintenance Excluding Fuel Expense				
9	Depreciation and Amortization				
10	Other Taxes				
11	**Total excluding Income Taxes**	$48,598		$48,598	= Sum (Lns. 7:11)
12	Operating Income Before Income Taxes	$ (48,598)		$ (48,598)	= Ln. 5 - Ln. 11
13	Income Taxes	(18,516)		(18,516)	= 38.10% x Ln. 12
14	**Operating Income After Income Taxes**	$ (30,082)		$ (30,082)	= Ln. 12 - Ln. 13
15	**Other Income (Deductions)**				
16	Income Taxes				
17	Allowance for Funds Used During Construction				
18	Other Income (Deductions)				
19	Other Expenses				
20	**Total**	$0		$0	= Sum (Lns. 16:19)
21	**Income Before Interest Deductions**	$ (30,082)		$ (30,082)	= Ln. 14 + Ln. 20
22	**Interest Deductions:**				
23	Interest on Long -Term Debt				
24	Interest on Short Term Borrowings				
25	Debt Discount, Premium and Expense				
26	Allowance for Borrowed Funds Used During Construction				
27	**Total**	$0		$0	= Sum (Lns. 23:26)
28	Net Income	$ (30,082)		$ (30,082)	= Ln. 21 - Ln. 27
29	Gross Revenue Conversion Factor			1.6155	
30	Estimated Revenue Requirement Impact			$ 48,598	

APS Updated Fuel & Purchased Power Expense

Line No.	Description	2015 TY Net Actual Expense[1] ($000s)	APS As-Filed 2017 Pro Forma Expense[2] ($000s)	APS Updated 2017 Pro Forma Expense[3] ($000s)	Updated vs. As-Filed F&PP Adjustment ($000s)
	(a)	(b)	(c)	(d)	(e) = (d) - (c)
1	Nuclear	$ 77,620	$ 70,423	$ 70,488	$ 64
2	Coal	206,187	226,444	228,154	1,710
3	Natural Gas	222,526	192,238	242,897	50,659
4	Purchased Power	172,312	130,251	130,452	201
5	Renewable	131,037	164,610	164,607	(3)
6	Fixed Gas Transport and Fuel Handling	76,382	86,220	86,220	0
7	Total Native Load	$ 886,063	$ 870,187	$ 922,819	$ 52,632
8	Off System Margin Credit	(38,414)	(16,727)	(19,993)	(3,265)
9	Net Retail Fuel Cost	$ 847,649	$ 853,460	$ 902,827	$ 49,367
10	Native Load Sales (GWH)	27,031	28,561	28,561	28,561
11	Net Fuel Cost Rate (¢/kWh)	3.1359	2.9882	3.1610	
12	Pro Forma vs 2015 TY		(0.1477)	0.0251	0.1728
13	TY Retail Sales (GWh)		27,950	27,950	
14	Weather Normalization Adjustment (GWh)		116	(285)	
15	Customer Normalization Adjustment (GWh)		116	115	
16	TY Adjusted Retail Sales (GWh)		28,182	27,781	
17	Pro Forma F & PP Expense Adjustment vs 2015 TY		$ (41,625)	$ 6,973	$\boxed{\$\ 48,598}$

Data Sources:

1. APS Witness Peter M. Ewen Attachment PME-04DR, p. 1 of 3.
2. APS Witness Peter M. Ewen Attachments PME-04DR, p. 2 of 3 and PME-03DR.
3. APS Response to Staff Data Request No. 1.13 Attachments PME-03TC and PME-04TC.

EXHIBIT KCH-3

Comparison of APS and AECC
Computation of Increase in Gross Revenue Requirements
For the Adjusted Test Year Ending December 31, 2015
(Thousands of Dollars)

Line No.	Description (a)	(b) ACC Jurisdiction APS Original Cost[1]	(c) AECC Adjustments	(d) AECC Original Cost
1	Adjusted Rate Base - Original Cost	$ 6,771,151	$ (30,300)	$ 6,740,851
2	Adjusted Operating Income	314,303	25,747	340,050
3	Current Rate of Return	4.64%	0.40%	5.04%
4	Required Operating Income	550,495	(30,775)	519,720
5	Requested Rate of Return	8.13%	-0.42%	7.71%
6	Adjusted Operating Income Deficiency	236,192	(56,522)	179,670
7	Gross Revenue Conversion Factor	1.6155		1.6155
8	Adjusted Increase in Base Revenue Requirement	$ 381,568	$ (91,312)	$ 290,256

Line No.	Description	APS FV Cost[1]	AECC Adjustments	AECC FV Cost
9	Adjusted Rate Base - RCND	13,180,895	(30,300)	13,150,595
10	Adjusted Rate Base - Fair Value (FV)	9,976,023	(30,300)	9,945,723
11	Fair Value Rate Base Increment	3,204,872	0	3,204,872
12	Requested Rate of Return with 1% FV Increment	5.84%	-0.29%	5.55%
13	Required Operating Income	582,600	(30,775)	551,825
14	Incremental Fair Value Required Operating Income	32,105	0	32,105
15	Gross Revenue Conversion Factor	1.6155		1.6155
16	Fair Value Increment	51,866	0	51,866
17	Requested Increase in Base Revenue Requirement	433,434	$ (91,312)	342,122
18	Rider Revenue Transferred to Base Rates	(267,551)	9,979	(257,572)
19	Net Requested Increase in Revenue Requirement	$ 165,883	$ (81,333)	$ 84,550
20	Total Present Sales Revenue to Ultimate Retail Customers	$ 2,888,903	$ -	$ 2,888,903
21	Adjusted Percentage Increase	5.74%	-2.82%	2.93%

Data Sources:
1. APS Schedule A-1 & H-1.

SUMMARY OF AECC RECOMMENDED COST OF CAPITAL
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Invested Capital	Adjusted End of Test Year 12/31/2015 Amount	%	Cost Rate	Composite Cost
1	Long-Term Debt	$3,728,555	44.20%	5.13%	2.27%
2	Preferred Stock	0	0.00%	0.00%	0.00%
3	Common Equity	4,706,351	55.80%	9.75%	5.44%
4	Short-Term Debt	0	0.00%	0.00%	0.00%
5	Total	$ 8,434,906	100.00%		7.71%

SUMMARY OF APS PROPOSED COST OF CAPITAL[1]
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Invested Capital	Adjusted End of Test Year 12/31/2015 Amount	%	Cost Rate	Composite Cost
6	Long-Term Debt	$3,728,555	44.20%	5.13%	2.27%
7	Preferred Stock	0	0.00%	0.00%	0.00%
8	Common Equity	4,706,351	55.80%	10.50%	5.86%
9	Short-Term Debt	0	0.00%	0.00%	0.00%
10	Total	$ 8,434,906	100.00%		8.13%

Data Source:
1. APS Standard Filing Requirements, Exhibit D-1, p. 1 of 2.

SUMMARY OF AECC RECOMMENDED COST OF CAPITAL WITH 1% FV INCREMENT
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

		Adjusted End of Test Year 12/31/2015			
Line No.	Invested Capital	Amount	%	Cost Rate	Composite Cost
1	Long-Term Debt	$ 2,979,456	29.96%	5.13%	1.54%
2	Preferred Stock	0	0.00%	0.00%	0.00%
3	Common Equity	3,761,395	37.82%	9.75%	3.69%
4	Short-Term Debt	0	0.00%	0.00%	0.00%
5	Fair Value Rate Base Increment	3,204,872	32.22%	1.00%	0.32%
6	Total	$ 9,945,723	100.00%		5.55%

SUMMARY OF APS PROPOSED COST OF CAPITAL WITH 1% FV INCREMENT[1]
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

		Adjusted End of Test Year 12/31/2015			
Line No.	Invested Capital	Amount	%	Cost Rate	Composite Cost
7	Long-Term Debt	$ 2,992,849	30.00%	5.13%	1.54%
8	Preferred Stock	0	0.00%	0.00%	0.00%
9	Common Equity	3,778,302	37.87%	10.50%	3.98%
10	Short-Term Debt	0	0.00%	0.00%	0.00%
11	Fair Value Rate Base Increment	3,204,872	32.13%	1.00%	0.32%
12	Total	$ 9,976,023	100.00%		5.84%

Data Source:
1. APS Witness Leland R. Snook Attachment LRS-03DR Calculation of Fair Value Increment.

AECC Original Cost Rate Base
For the Adjusted Test Year Ending December 31, 2015
(Thousands of Dollars)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		APS Application[1] Adjusted Test Year Ended 12/31/2015		AECC Test Year Pro Forma STAR Ctr. Patents Adjustment		AECC Test Year Pro Forma ADIT Adjustment		AECC Adjusted Test Year Ended 12/31/2015	
Line No.	Description	Total Company	ACC Jurisdiction	Total Company	ACC Jurisdiction	Total Company	ACC Jurisdiction	Total Company	ACC Jurisdiction
1	Gross Utility Plant in Service	$ 17,936,120	$ 15,436,960	$ 0	$ 0	$ 0	$ 0	$ 17,936,120	$ 15,436,960
2	Less: Accumulated Depreciation and Amortization	7,129,944	6,344,512	0	0	0	0	7,129,944	6,344,512
3	Net Utility Plant in Service	10,806,176	9,092,448	0	0	0	0	10,806,176	9,092,448
4	Less: Total Deductions	5,297,316	4,688,459	688	688	34,753	29,612	5,332,757	4,718,759
5	Plus: Total Additions	2,502,940	2,367,162	0	0	0	0	2,502,940	2,367,162
6	Total Rate Base	$ 8,011,800	$ 6,771,151	$ (688)	$ (688)	$ (34,753)	$ (29,612)	$ 7,976,359	$ 6,740,851

Data Source:
1. APS SFR Schedule B-1, p. 1 of 2.

AECC RCND Rate Base
For the Adjusted Test Year Ending December 31, 2015
(Thousands of Dollars)

		APS Application[1] Adjusted Test Year Ended 12/31/2015		AECC Year Pro Forma Star Ctr. Patents Adjustment		AECC Test Year Pro Forma ADIT Adjustment		AECC Adjusted Test Year Ended 12/31/2015	
Line No.	Description	Total Company	ACC Jurisdiction	Total Company	ACC Jurisdiction	Total Company	ACC Jurisdiction	Total Company	ACC Jurisdiction
7	Gross Utility Plant in Service	$ 36,056,872	$ 30,895,769	$ 0	$ 0	$ 0	$ 0	$ 36,056,872	$ 30,895,769
8	Less: Accumulated Depreciation and Amortization	14,386,705	12,728,418	0	0	0	0	14,386,705	12,728,418
9	Net Utility Plant in Service	21,670,167	18,167,351	0	0	0	0	21,670,167	18,167,351
10	Less: Total Deductions	8,542,646	7,353,618	688	688	34,753	29,612	8,578,086	7,383,918
11	Plus: Total Additions	2,502,940	2,367,162	0	0	0	0	2,502,940	2,367,162
12	Total Rate Base	$ 15,630,461	$ 13,180,895	$ (688)	$ (688)	$ (34,753)	$ (29,612)	$ 15,595,021	$ 13,150,595

Data Source:
1. APS SFR Schedule B-1, p. 2 of 2.

AECC Income Statement
For the Adjusted Test Year Ending December 31, 2015
(Thousands of Dollars)

Line No.	(a) Description	(b) APS Application[1] Adjusted Test Year Ended 12/31/2015 Total Company	(c) APS Application[1] Adjusted Test Year Ended 12/31/2015 ACC Jurisdiction	(d) AECC Post Test Period Depreciation Exp. Adjustment Total Company	(e) AECC Post Test Period Depreciation Exp. Adjustment ACC Jurisdiction	(f) AECC Test Year Pro Forma Payroll Expense Adjustment Total Company	(g) AECC Test Year Pro Forma Payroll Expense Adjustment ACC Jurisdiction	(h) AECC Test Year Pro Forma Incentive Comp. Adjustment Total Company	(i) AECC Test Year Pro Forma Incentive Comp. Adjustment ACC Jurisdiction
	Electric Operating Revenues								
1	Revenues from Base Rates	$ 2,932,988	$ 2,888,903	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
2	Revenues from Surcharges	0	0	0	0	0	0	0	0
3	Other Electric Revenues	170,101	158,550	0	0	0	0	0	0
4	Total	3,103,089	3,047,453	0	0	0	0	0	0
	Operating Expenses:								
5	Electric Fuel and Purchased Power	998,924	992,062	0	0	0	0	0	0
6	Operations and Maintenance Excluding Fuel Expense	763,118	918,028	0	0	(1,941)	(1,793)	(21,414)	(19,787)
7	Depreciation and Amortization	608,865	550,431	(10,378)	(9,660)	0	0	0	0
8	Income Taxes	126,347	96,160	3,954	3,680	739	683	8,159	7,539
9	Other Taxes	213,691	176,469	0	0	0	0	0	0
10	Total	2,710,945	2,733,150	(6,424)	(5,979)	(1,202)	(1,110)	(13,255)	(12,248)
11	Operating Income	392,144	314,303	6,424	5,979	1,202	1,110	13,255	12,248
	Other Income (Deductions)								
12	Income Taxes	14,302	0	0	0	0	0	0	0
13	Allowance for Funds Used During Construction	35,215	0	0	0	0	0	0	0
14	Other Income (Deductions)	2,834	0	0	0	0	0	0	0
15	Other Expenses	(19,019)	0	0	0	0	0	0	0
16	Total	33,332	0	0	0	0	0	0	0
17	Income Before Interest Deductions	425,476	314,303	6,424	5,979	1,202	1,110	13,255	12,248
	Interest Deductions:								
18	Interest on Long -Term Debt	179,563	0	0	0	0	0	0	0
19	Interest on Short Term Borrowings	7,376	0	0	0	0	0	0	0
20	Debt Discount, Premium and Expense	4,793	0	0	0	0	0	0	0
21	Allowance for Borrowed Funds Used During Construction	(16,183)	0	0	0	0	0	0	0
22	Total	175,549	0	0	0	0	0	0	0
23	Net Income	$ 249,927	$ 314,303	$ 6,424	$ 5,979	$ 1,202	$ 1,110	$ 13,255	$ 12,248

Data Source:
1. APS SFR Schedule C-1.

AECC Income Statement
For the Adjusted Test Year Ending December 31, 2015
(Thousands of Dollars)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		AECC Year Pro Forma DSMAC Expense Adjustment		AECC Year Pro Forma STAR Ctr. Patents Adjustment		AECC Proforma	
Line No.	Description	Total Company	ACC Jurisdiction	Total Company	ACC Jurisdiction	Total Company	ACC Jurisdiction
	Electric Operating Revenues						
1	Revenues from Base Rates	$ 0	$ 0	$ 0	$ 0	$ 2,932,988	$ 2,888,903
2	Revenues from Surcharges	0	0	0	0	0	0
3	Other Electric Revenues	0	0	0	0	170,101	158,550
4	Total			0	0	3,103,089	3,047,453
	Operating Expenses:						
5	Electric Fuel and Purchased Power	0	0	0	0	998,924	992,062
6	Operations and Maintenance Excluding Fuel Expense	(10,000)	(9,979)	(375)	(375)	729,388	886,093
7	Depreciation and Amortization	0	0	0	0	598,487	540,771
8	Income Taxes	3,810	3,802	143	143	143,152	112,007
9	Other Taxes	0	0	0	0	213,691	176,469
10	Total	(6,190)	(6,177)	(232)	(232)	2,683,642	2,707,403
11	Operating Income	6,190	6,177	232	232	419,447	340,050
	Other Income (Deductions)						
12	Income Taxes	0	0	0	0	14,302	0
13	Allowance for Funds Used During Construction	0	0	0	0	35,215	0
14	Other Income (Deductions)	0	0	0	0	2,834	0
15	Other Expenses	0	0	0	0	(19,019)	0
16	Total	0	0	0	0	33,332	0
17	Income Before Interest Deductions	6,190	6,177	232	232	452,779	340,050
	Interest Deductions:						
18	Interest on Long -Term Debt	0	0	0	0	179,563	0
19	Interest on Short Term Borrowings	0	0	0	0	7,376	0
20	Debt Discount, Premium and Expense	0	0	0	0	4,793	0
21	Allowance for Borrowed Funds Used During Construction	0	0	0	0	(16,183)	0
22	Total	0	0	0	0	175,549	0
23	Net Income	$ 6,190	$ 6,177	$ 232	$ 232	$ 277,230	$ 340,050

EXHIBIT KCH-4

AECC Post-Test Year Plant Additions Depreciation Expense Adjustment

Income Statement Impact
(Thousands of Dollars)

Pro Forma Adjustment: **Post-Test Year Plant Additions Depreciation Expense**
AECC Adjustment to Post-Test Year Plant Additions Depreciation Expense to be Consistent with Accumulated Depreciation

Line No.	Description	AECC Total Company Amount	ACC Jurisdictional Allocation Factor	AECC ACC Jurisdictional Amount	Source
	(a)	(b)	(c)	(d)	(e)
1	**Electric Operating Revenues**				
2	Revenues from Base Rates				
3	Revenues from Surcharges				
4	Other Electric Revenues				
5	**Total**	$0		$0	= Sum (Lns. 2:4)
6	**Operating Expenses:**				
7	Electric Fuel and Purchased Power				
8	Operations and Maintenance Excluding Fuel Expense				
9	Depreciation and Amortization	$ (10,378)	93.08%	$ (9,660)	See Page 2, Ln. 14, Cols. (f) & (h).
10	Other Taxes				
11	**Total excluding Income Taxes**	($10,378)		($9,660)	= Sum (Lns. 7:10)
12	Operating Income Before Income Taxes	$ 10,378		$ 9,660	= Ln. 5 - Ln. 11
13	Income Taxes	3,954		3,680	= 38.10% x Ln. 12
14	**Operating Income After Income Taxes**	$ 6,424		$ 5,979	= Ln. 12 - Ln. 13
15	**Other Income (Deductions)**				
16	Income Taxes				
17	Allowance for Funds Used During Construction				
18	Other Income (Deductions)				
19	Other Expenses				
20	**Total**	$0		$0	= Sum (Lns. 16:19)
21	**Income Before Interest Deductions**	$ 6,424		$ 5,979	= Ln. 14 + Ln. 20
22	**Interest Deductions:**				
23	Interest on Long -Term Debt				
24	Interest on Short Term Borrowings				
25	Debt Discount, Premium and Expense				
26	Allowance for Borrowed Funds Used During Construction				
27	**Total**	$0		$0	= Sum (Lns. 23:26)
28	Net Income	$ 6,424		$ 5,979	= Ln. 21 - Ln. 27
29	Gross Revenue Conversion Factor			1.6155	
30	Estimated Revenue Requirement Impact			$ (9,660)	= Ln. 28 x Ln. 29

AECC Post-Test Year Plant Additions Depreciation Expense Adjustment Derivation

Line No.	Description	Plant Additions	Depreciation Rate	APS Proposed Accumulated Depreciation [1]	APS Proposed Depreciation Expense [2]	AECC Recommended Depreciation Expense Adjustment	ACC Allocator[3]	ACC Allocated AECC Adjustment
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	**Distribution**	**270,492**	**2.45%**	**6,377**	**6,627**	**(250)**	99.964%	**(250)**
2	General	62,438	6.20%	3,060	3,871	(811)	92.404%	(750)
3	Intangible	137,457	10.00%	11,141	13,746	(2,605)	92.404%	(2,407)
4	**Total General & Intangibles**	**199,894**		**14,201**	**17,617**	**(3,416)**		**(3,157)**
5	**Nuclear Production**	**123,961**	**1.62%**	**1,744**	**2,008**	**(264)**	99.460%	**(263)**
6	**Renewables**	**156,754**	**3.86%**	**6,046**	**6,051**	**(5)**	100.000%	**(5)**
7	Modern Grid - Distribution	47,983	2.45%	1,076	1,176	(99)	99.964%	(99)
8	Modern Grid - Meters	33,772	5.00%	1,576	1,689	(113)	99.964%	(113)
9	**Total Modern Grid**	**81,755**		**2,652**	**2,864**	**(212)**		**(212)**
10	**Customer Service**	**120,485**	**10.00%**	**6,050**	**12,048**	**(5,999)**	92.404%	**(5,543)**
11	Steam Production	108,740	4.50%	4,803	4,893	(90)	99.460%	(89)
12	Other Production	51,895	3.82%	1,841	1,982	(142)	99.460%	(141)
13	**Total Fossil**	**160,635**		**6,644**	**6,876**	**(232)**		**(230)**
14	**Total PTYP Additions**	**1,113,976**		**43,713**	**54,091**	**(10,378)**	93.081%	**(9,660)**

Data Sources:
1. EAB_WP07DR RB Pro Forma Post Test Year Plant Additions.
2. EAB_WP33DR IS Pro Forma Post Test Year Plant Additions.
3. Allocation approximated based on the allocation of depreciation expense in APS's Response to AECC's Data Request 15.5, Attachment APSRC01783.

EXHIBIT KCH-5

AECC Payroll Expense Adjustment

Income Statement Impact
(Thousands of Dollars)

Pro Forma Adjustment: **Test Year Payroll Expense**
AECC Adjustment to Reflect Proper Payroll Expense in APS's Test Year Operations and Maintenance Expenses

Line No.	Description	AECC Total Company Amount	ACC Jurisdictional Allocation Factor	AECC ACC Jurisdictional Amount	Source
	(a)	(b)	(c)	(d)	(e)
1	**Electric Operating Revenues**				
2	Revenues from Base Rates				
3	Revenues from Surcharges				
4	Other Electric Revenues				
5	**Total**	$0		$0	= Sum (Lns. 2:4)
6	**Operating Expenses:**				
7	Electric Fuel and Purchased Power				
8	Operations and Maintenance Excluding Fuel Expense	($1,941)	92.40%	($1,793)	See Page 2, Ln. 5, Col. (o).
9	Depreciation and Amortization				
10	Other Taxes				
11	**Total excluding Income Taxes**	($1,941)		($1,793)	= Sum (Lns. 7:10)
12	Operating Income Before Income Taxes	$ 1,941		$ 1,793	= Ln. 5 - Ln. 11
13	Income Taxes	739		683	= 38.10% x Ln. 12
14	**Operating Income After Income Taxes**	**$ 1,202**		**$ 1,110**	= Ln. 12 - Ln. 13
15	**Other Income (Deductions)**				
16	Income Taxes				
17	Allowance for Funds Used During Construction				
18	Other Income (Deductions)				
19	Other Expenses				
20	**Total**	$0		$0	= Sum (Lns. 16:19)
21	**Income Before Interest Deductions**	$ 1,202		$ 1,110	= Ln. 14 + Ln. 20
22	**Interest Deductions:**				
23	Interest on Long -Term Debt				
24	Interest on Short Term Borrowings				
25	Debt Discount, Premium and Expense				
26	Allowance for Borrowed Funds Used During Construction				
27	**Total**	$0		$0	= Sum (Lns. 23:26)
28	Net Income	$ 1,202		$ 1,110	= Ln. 21 - Ln. 27
29	Gross Revenue Conversion Factor			1.6155	
30	Estimated Revenue Requirement Impact			$ (1,794)	= Ln. 28 x Ln. 29

AECC Payroll Expense Adjustment

AECC Proposed Payroll Expense Adjustment

Line No.	(a) Description	(b) Test Year Unadjusted O&M Labor Expense[1]	(c) March 14, 2016 Annualized O&M Payroll Expense[1]	(d) Apr-16 Annualized Union 387 Payroll Expense w/ 2.25% Increase	(e) Apr-17 Proforma Union 387 Payroll Expense w/ 3.00% Increase	(f) Jun-15 Annualized USP Payroll Expense w/ 0.00% Increase	(g) Jun-16 Annualized USP Payroll Expense w/ 1.49% Increase	(h) Test Year Adjusted O&M Labor Expense	(i) AECC Proposed Payroll Expense Adjustment Before Loading	(j) Payroll Expense Loading: Payroll Taxes @ 7.0%	(k) Payroll Expense Loading: Group Insurance Loading @ 11.68%	(l) Payroll Expense Loading: Employee Savings Loading @ 3.4%	(m) Payroll Expense Loading: Employee Pension Loading @ 0.0%	(n) Payroll Expense Loading: Employee OPEB Loading @ 0.0%	(o) AECC Proposed Payroll Expense Adjustment	(p) Operations Share @ 79.50%	(q) Maintenance Share @ 20.50%
		Total Company															
1	Performance	209,454,802	210,486,893					210,486,893	1,032,091	72,246	120,537	34,783	0	0	1,259,657	1,001,407	258,250
2	IBEW 387/Supplemental	69,209,457	68,921,283	70,472,012	70,988,922			70,988,922	1,779,465	124,563	207,822	59,971	0	0	2,171,820	1,726,561	445,259
3	USP	3,170,505	3,088,979			3,088,979	3,135,005	3,135,005	(35,500)	(2,485)	(4,146)	(1,196)	0	0	(43,327)	(34,444)	(8,883)
4	TOTAL	281,834,764	282,497,156					284,610,820	2,776,056	194,324	324,212	93,557	0	0	3,388,149	2,693,523	694,626
5	Adjustment from APS As-Filed [= Ln.4 - Ln. 9]							(1,589,959)	(1,589,959)	(111,297)	(185,689)	(53,584)	0	0	$\boxed{(1,940,529)}$	(1,542,689)	(397,840)

1. Data Source: APS Witness Elizabeth A. Blankenship workpaper EAB WP35DR IS Pro Forma Annualize Payroll Expense.

APS Proposed Payroll Expense Adjustment

Line No.	(a) Description	(b) Test Year Unadjusted O&M Labor Expense	(c) March 14, 2016 Annualized O&M Payroll Expense	(d) Apr-16 Annualized Union 387 Payroll Expense w/ 2.25% Increase	(e) Apr-17 Annualized Union 387 Payroll Expense w/ 3.00% Increase	(f) Jun-15 Annualized USP Payroll Expense w/ 1.27% Increase	(g) Jun-16 Annualized USP Payroll Expense w/ 1.49% Increase	(h) Test Year Adjusted O&M Labor Expense	(i) APS Proposed Payroll Expense Adjustment Before Loading	(j) Payroll Expense Loading: Payroll Taxes @ 7.0%	(k) Payroll Expense Loading: Group Insurance Loading @ 11.68%	(l) Payroll Expense Loading: Employee Savings Loading @ 3.4%	(m) Payroll Expense Loading: Employee Pension Loading @ 0.0%	(n) Payroll Expense Loading: Employee OPEB Loading @ 0.0%	(o) APS Proposed Payroll Expense Adjustment	(p) Operations Share @ 79.50%	(q) Maintenance Share @ 20.50%
		Total Company[2]															
6	Performance	209,454,802	210,486,893					210,486,893	1,032,091	72,246	120,537	34,783	0	0	1,259,657	1,001,407	258,250
7	IBEW 387/Supplemental	69,209,457	68,921,283	70,472,012	72,539,651			72,539,651	3,330,194	233,114	388,929	112,232	0	0	4,064,469	3,231,186	833,283
8	USP	3,170,505	3,088,979			3,128,209	3,174,235	3,174,235	3,730	261	436	126	0	0	4,553	3,619	933
9	TOTAL	281,834,764	282,497,156					286,200,779	4,366,015	305,621	509,902	147,141	0	0	5,328,679	4,236,212	1,092,467

2. Data Source: APS Witness Elizabeth A. Blankenship workpaper EAB WP35DR IS Pro Forma Annualize Payroll Expense.

EXHIBIT KCH-6

AECC Cash Incentive Expense Adjustment

Income Statement Impact
(Thousands of Dollars)

Pro Forma Adjustment: **Test Year Cash Incentive Expense**
AECC Adjustment to Remove Cash Incentive Expense Related to Financial Performance, Normalized Over a 3 Year Period.

Line No.	Description	AECC Total Company Amount	ACC Jurisdictional Allocation Factor	AECC ACC Jurisdictional Amount	Source
	(a)	(b)	(c)	(d)	(e)
1	**Electric Operating Revenues**				
2	Revenues from Base Rates				
3	Revenues from Surcharges				
4	Other Electric Revenues				
5	**Total**	$0		$0	= Sum (Lns. 2:4)
6	**Operating Expenses:**				
7	Electric Fuel and Purchased Power				
8	Operations and Maintenance Excluding Fuel Expense	($21,414)	92.40%	($19,787)	See Page 2, Ln. 16, Col. (d).
9	Depreciation and Amortization				
10	Other Taxes				
11	**Total excluding Income Taxes**	($21,414)		($19,787)	= Sum (Lns. 7:10)
12	Operating Income Before Income Taxes	$ 21,414		$ 19,787	= Ln. 5 - Ln. 11
13	Income Taxes	8,159		7,539	= 38.10% x Ln. 12
14	**Operating Income After Income Taxes**	**$ 13,255**		**$ 12,248**	= Ln. 12 - Ln. 13
15	**Other Income (Deductions)**				
16	Income Taxes				
17	Allowance for Funds Used During Construction				
18	Other Income (Deductions)				
19	Other Expenses				
20	**Total**	$0		$0	= Sum (Lns. 16:19)
21	**Income Before Interest Deductions**	$ 13,255		$ 12,248	= Ln. 14 + Ln. 20
22	**Interest Deductions:**				
23	Interest on Long -Term Debt				
24	Interest on Short Term Borrowings				
25	Debt Discount, Premium and Expense				
26	Allowance for Borrowed Funds Used During Construction				
27	**Total**	$0		$0	= Sum (Lns. 23:26)
28	Net Income	$ 13,255		$ 12,248	= Ln. 21 - Ln. 27
29	Gross Revenue Conversion Factor			1.6155	
30	Estimated Revenue Requirement Impact			$\boxed{\$ \quad (19,787)}$	= Ln. 28 x Ln. 29

AECC Cash Incentive Expense Adjustment Derivation

Line No.	Description	APS Proposed Total Company TY Cash Incentive Adjustment	AECC Recommended Total Company TY Cash Incentive Adjustment	Incremental AECC Recommended Total Company TY Cash Incentive Adjustment
	(a)	(b)	(c)	(d)
1	Electric Operating Revenues			
2	Revenues from Base Rates	$ -	$ -	$ -
3	Revenues from Surcharges	-	-	-
4	Other Electric Revenues	-	-	-
5	Total Electric Operating Revenues	-	-	-
6	Electric Fuel and Purchased Power Costs	-	-	-
7	Oper Rev Less Fuel & Purch Pwr Costs	-	-	-
8	Other Operating Expenses:			
9	Operations Excluding Fuel Expense	(2,029)	(15,597)	(13,568)
10	Maintenance	(50)	(487)	(437)
11	Subtotal	(2,079)	(16,084)	(14,005)
12	Depreciation and Amortization	-	-	-
13	Amortization of Gain	-	-	-
14	Administrative and General	(928)	(8,337)	(7,409)
15	Other Taxes	-	-	-
16	Total Other Operating Expense	(3,007)	(24,421)	(21,414)
17	Operating Income Before Income Tax	3,007	24,421	21,414
18	Interest Expense	-	-	-
19	Taxable Income	3,007	24,421	21,414
20	Current Income Tax Rate - 38.10% (line 19 * 38.1%)	1,146	9,304	8,158
21	Operating Income (line 15 minus line 18)	$ 1,861	$ 15,117	$ 13,256

Adjustment to Test Year operations to remove cash incentive related to financial performance, normalized over a 3 year period.

AECC Estimate of Non-Financial Performance Cash Incentive Expense

Line No.	(a)	Total Cash Incentive Expense Total Company[1] 2013 (b)	2014 (c)	2015 (d)	Estimated Non-Financial Performance Portion Total Company 2013 (e)	2014 (f)	2015 (g)
1	Account						
2	500	$ -	$ -	$ -	$ -	$ -	$ -
3	506	3,493	3,374	4,349	1,412	1,736	1,900
4	510	0	0	0	0	0	0
5	512	0	0	0	0	0	0
6	514	0	0	0	0	0	0
7	519	844	923	996	341	475	435
8	524	7,594	8,310	8,956	3,069	4,275	3,913
9	546	1,149	1,237	14	464	636	6
10	549	0	0	2,236	0	0	977
11	557	801	738	607	324	380	265
12	566	1,363	1,188	1,634	551	611	714
13	580	140	12	0	57	6	0
14	586	0	0	187	0	0	82
15	588	5,245	4,401	4,175	2,120	2,264	1,824
16	593	0	0	69	0	0	30
17	598	0	0	168	0	0	73
18	903	3,034	3,621	3,300	1,226	1,863	1,442
19	908	0	0		0	0	0
20	916	618	658	873	250	338	381
21	920	15,053	13,529	15,570	6,084	6,959	6,804
22	926	225	336	302	91	173	132
23	928	328	347	552	133	178	241
24	930.2	1,407	1,085	1,466	569	558	641
25		$ 41,294	$ 39,759	$ 45,454	$ 16,689	$ 20,452	$ 19,862
26	Share Allocated to APS from Pinnacle West						
27	Total	$ 2,215	$ 1,851	$ 2,276			
28	Company Earnings Performance Portion[2]	1,392	921	920			
29	Non-Pinnacle West Share						
30	Total[3]	39,079	37,908	43,178			
31	Company Performance[4]	17,043	12,880	17,476			
32	Business Unit Performance[4]	22,036	25,028	25,702			
33	Shareholder Value % of Business Unit Perf.[4]	28%	22%	28%			
34	Total Financial Performance Portion	23,213	18,386	24,673			
35	Total APS Incentive Compensation Expense						
36	Total Non-Financial Performance Portion	16,689	20,452	19,862			
37	Total Non-Financial Performance Proportion	40.41%	51.44%	43.70%			
38	Participant A&G Credit (net APS A&G)	(3,749)	(3,126)	(3,598)	(1,515)	(1,608)	(1,572)
39	Net O&M Incentive	$ 37,545	$ 36,633	$ 41,856	$ 15,173	$ 18,844	$ 18,290

Line No.	(a)	Total APS	Operations	Maintenance	A&G	Total APS	Operations	Maintenance	A&G
40		Total APS	Operations	Maintenance	A&G	Total APS	Operations	Maintenance	A&G
41		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
42	3 Year Average	38,678	24,641	794	13,242	17,435	11,123	357	5,955
43	Less 2015 Incentive Amount	41,856	26,720	844	14,292	41,856	26,720	844	14,292
44	Adjustment to Incentive	(3,178)	(2,079)	(50)	(1,050)	(24,421)	(15,597)	(487)	(8,337)

Data Sources:
1. APS's Fifth Supplemental Response to Staff Data Request 1.13, APSRC01735.
2. APS's response to AECC Data Request 15.1.
3. EAB_WP39DR IS Pro Forma Normalize Cash Incentive.
4. APS's response to AECC Data Request 6.1.

EXHIBIT KCH-7

AECC Demand Side Management Expense Adjustment

Income Statement Impact
(Thousands of Dollars)

Pro Forma Adjustment: **Test Year Demand Side Management (DSM) Expense**
AECC Adjustment to Remove APS's Proposed DSM Expense Transfer to Base Rates.

Line No.	Description	AECC Total Company Amount	ACC Jurisdictional Allocation Factor	AECC ACC Jurisdictional Amount	Source
	(a)	(b)	(c)	(d)	(e)
1	**Electric Operating Revenues**				
2	Revenues from Base Rates				
3	Revenues from Surcharges				
4	Other Electric Revenues				
5	**Total**	$0		$0	= Sum (Lns. 2:4)
6	**Operating Expenses:**				
7	Electric Fuel and Purchased Power				
8	Operations and Maintenance Excluding Fuel Expense	($10,000)	99.79%	($9,979)	See APS EAB_WP24DR.
9	Depreciation and Amortization				
10	Other Taxes				
11	**Total excluding Income Taxes**	($10,000)		($9,979)	= Sum (Lns. 7:10)
12	Operating Income Before Income Taxes	$ 10,000		$ 9,979	= Ln. 5 - Ln. 11
13	Income Taxes	3,810		3,802	= 38.10% x Ln. 12
14	**Operating Income After Income Taxes**	**$ 6,190**		**$ 6,177**	= Ln. 12 - Ln. 13
15	**Other Income (Deductions)**				
16	Income Taxes				
17	Allowance for Funds Used During Construction				
18	Other Income (Deductions)				
19	Other Expenses				
20	**Total**	**$0**		**$0**	= Sum (Lns. 16:19)
21	**Income Before Interest Deductions**	$ 6,190		$ 6,177	= Ln. 14 + Ln. 20
22	**Interest Deductions:**				
23	Interest on Long -Term Debt				
24	Interest on Short Term Borrowings				
25	Debt Discount, Premium and Expense				
26	Allowance for Borrowed Funds Used During Construction				
27	**Total**	**$0**		**$0**	= Sum (Lns. 23:26)
28	Net Income	$ 6,190		$ 6,177	= Ln. 21 - Ln. 27
29	Gross Revenue Conversion Factor			1.6155	
30	Estimated Revenue Requirement Impact			$ (9,979)	= Ln. 28 x Ln. 29

EXHIBIT KCH-8

AECC STAR Center Patent Rights Adjustment

Income Statement Impact
(Thousands of Dollars)

Pro Forma Adjustment: **STAR Center Patent Rights Amortization**
AECC Adjustment to Recognize the Remaining 50% of STAR Center Patent Rights as a Credit to Customers

Line No.	Description	AECC Total Company Amount	ACC Jurisdictional Allocation Factor	AECC ACC Jurisdictional Amount	Source
1	**Electric Operating Revenues**				
2	Revenues from Base Rates				
3	Revenues from Surcharges				
4	Other Electric Revenues				
5	**Total**	$0		$0	= Sum (Lns. 2:4)
6	**Operating Expenses:**				
7	Electric Fuel and Purchased Power				
8	Operations and Maintenance Excluding Fuel Expense	($375)	100.00%	($375)	See Note 1.
9	Depreciation and Amortization				
10	Other Taxes				
11	**Total excluding Income Taxes**	($375)		($375)	= Sum (Lns. 7:10)
12	Operating Income Before Income Taxes	$ 375		$ 375	= Ln. 5 - Ln. 11
13	Income Taxes	143		143	= 38.10% x Ln. 12
14	**Operating Income After Income Taxes**	**$ 232**		**$ 232**	= Ln. 12 - Ln. 13
15	**Other Income (Deductions)**				
16	Income Taxes				
17	Allowance for Funds Used During Construction				
18	Other Income (Deductions)				
19	Other Expenses				
20	**Total**	**$0**		**$0**	= Sum (Lns. 16:19)
21	**Income Before Interest Deductions**	$ 232		$ 232	= Ln. 14 + Ln. 20
22	**Interest Deductions:**				
23	Interest on Long -Term Debt				
24	Interest on Short Term Borrowings				
25	Debt Discount, Premium and Expense				
26	Allowance for Borrowed Funds Used During Construction				
27	**Total**	**$0**		**$0**	= Sum (Lns. 23:26)
28	Net Income	$ 232		$ 232	= Ln. 21 - Ln. 27
29	Gross Revenue Conversion Factor			1.6155	
30	Estimated Revenue Requirement Impact			$ (375)	= Ln. 28 x Ln. 29

Note 1: APS's response to AECC Data Request 4.1(f), Attachment APSRC01560. AECC's adjustment amortizes $1,125,393 over 3 years.

AECC STAR Center Patent Rights Adjustment

Rate Base Impact
(Thousands of Dollars)

Pro Forma Adjustment: **STAR Center Patent Rights Amortization**
AECC Adjustment to Recognize the Remaining 50% of STAR Center Patent Rights as a Credit to Customers

		AECC Recommended Rate Base Adjustment for STAR Center Patent Rights Proceeds			
Line No.	**Description**	**AECC Total Company Amount**	**ACC Jurisdictional Allocation Factor**	**AECC ACC Jurisdictional Amount**	**Source**
	(a)	**(b)**	**(c)**	**(d)**	**(e)**
1	Gross Utility Plant in Service	$ -		$ -	
2	Less: Accumulated Depreciation & Amort.	-		-	
3	Net Utility Plant in Service	-		-	
4	Less: Total Deductions	688	100%	688	See Note 1.
5	Total Additions	-		-	
6	Total Rate Base	$ (688)		$ (688)	= Ln. 3 - Ln. 4 + Ln. 5
	Original Cost Impact				
7	APS Requested Rate of Return			8.13%	
8	Required Operating Income			(56)	= Ln. 6 x Ln. 7
9	Gross Revenue Conversion Factor			1.6155	
10	Estimated Revenue Requirement Impact			$ (91)	= Ln. 8 x Ln. 9

Note 1: Data Source: EAB_WP05DR Schedule B-1, "Reg Asset" tab.
AECC's adjustment recognizes the net regulatory liability associated with the remaining 50% of STAR Center Patent Rights proceeds.

EXHIBIT KCH-9

AECC ADIT Adjustment
Rate Base Impact
(Thousands of Dollars)

Pro Forma Adjustment: ADIT Adjustment
AECC ADIT Adjustment Based on 50% Apportionment of 2017 Tax Depreciation Expense.

AECC Recommended ADIT Adjustment

Line No.	Description	AECC Total Company Amount	ACC Jurisdictional Allocation Factor	AECC ACC Jurisdictional Amount	Source
	(a)	(b)	(c)	(d)	(e)
1	Gross Utility Plant in Service	$ -		$ -	
2	Less: Accumulated Depreciation & Amort.	-		-	
3	Net Utility Plant in Service	-		-	= Ln. 1 - Ln. 2
4	Less: Total Deductions	34,753	85.208%	29,612	See Page 2, Ln. 9, Cols. (b) & (e).
5	Total Additions	-		-	
6	Total Rate Base	$ (34,753)		$ (29,612)	= Ln. 3 - Ln. 4 + Ln. 5
	Original Cost Impact				
7	APS Requested Rate of Return			8.13%	
8	Required Operating Income			(2,407)	= Ln. 6 x Ln. 7
9	Gross Revenue Conversion Factor			1.6155	
10	Estimated Revenue Requirement Impact			$ (3,890)	= Ln. 8 x Ln. 9

ACC Allocation of AECC ADIT Adjustment

Line No.	Description	AECC Adjustment to Deferred Tax Liability	ACC Allocator[1]	ACC Allocated AECC Adjustment
	(a)	(b)	(c)	(e)
1	Distribution	10,009	99.964%	10,005
2	General & Intangible	4,227	92.404%	3,906
3	Nuclear Production	3,109	99.460%	3,093
4	Renewables	3,171	100.000%	3,171
5	Total Modern Grid	682	99.964%	682
6	Customer Service	3,649	92.404%	3,372
7	Total Fossil	5,412	99.460%	5,383
8	Transmission	4,493	0.000%	0
9	**Total Deferred Tax Liability Adj.**	**34,753**	**85.208%**	**29,612**

Data Sources:
1. Allocation approximated based on APS's Response to AECC's Data Request 15.5, Attachment APSRC01783.

AECC Post-Test Year Plant Additions ADIT Adjustment Derivation

			FEDERAL		
				50%	35%
Line No.	Description	APS Book Incremental Accumulated Depreciation Jan.-Jun. 2017 [1]	APS Tax Year 2017 Federal Depreciation Expense [1]	Apportioned Tax Year 2017 Federal Depreciation Expense for Jan.-Jun. 2017	AECC Recommended Federal ADIT for Jan.-Jun. 2017
1	Distribution	3,314	19,605	9,802	2,271
2	General - Buildings	1,596	991	496	(385)
3	General - Other	339	2,014	1,007	234
4	Intangible - Software	6,873	44,616	22,308	5,402
5	Total General & Intangibles	8,808	47,622	23,811	5,251
6	Nuclear Production	1,004	21,465	10,732	3,405
7	Renewables	3,025	21,816	10,908	2,759
8	Modern Grid - Distribution	588	5,643	2,821	782
9	Modern Grid - Meters	844	7,390	3,695	998
10	Total Modern Grid	1,432	13,032	6,516	1,779
11	Customer Service	6,024	68,623	34,312	9,901
12	Steam Production	2,447	5,853	2,926	168
13	Combined Cycle	459	2,509	1,255	278
14	Combustion Turbine	532	3,240	1,620	381
15	Total Fossil	3,438	11,602	5,801	827
16	Total	27,046	203,766	101,883	26,193

			STATE			TOTAL		
				50%	3.10%			
Line No.	Description	APS Book Incremental Accumulated Depreciation Jan.-Jun. 2017 [2]	APS Tax Year 2017 State Depreciation Expense [2]	Apportioned Tax Year 2017 State Depreciation Expense for Jan.-Jun. 2017	AECC Recommended State ADIT for Jan.-Jun. 2017	APS Total Jan.-Jun. 2017 ADIT [3]	AECC Total Jan.-Jun. 2017 ADIT	AECC Recommended Post-Test Year ADIT Adjustment
17	Distribution	3,314	18,820	9,410	189	1,759	2,460	701
18	General - Buildings	1,596	991	496	(34)	(66)	(419)	(354)
19	General - Other	339	2,527	1,264	29	186	262	76
20	Intangible - Software	6,873	37,136	18,568	363	4,025	5,765	1,740
21	Total General & Intangibles	8,808	40,655	20,327	357	4,146	5,608	1,462
22	Nuclear Production	1,004	10,308	5,154	129	2,119	3,534	1,414
23	Renewables	3,025	50,130	25,065	683	2,287	3,442	1,156
24	Modern Grid - Distribution	588	3,183	1,591	31	526	813	287
25	Modern Grid - Meters	844	10,265	5,133	133	735	1,131	396
26	Total Modern Grid	1,432	13,448	6,724	164	1,261	1,943	682
27	Customer Service	6,024	17,269	8,634	81	6,332	9,982	3,649
28	Steam Production	2,447	7,711	3,856	44	386	212	(174)
29	Combined Cycle	459	1,617	809	11	214	289	75
30	Combustion Turbine	532	2,466	1,233	22	287	403	116
31	Total Fossil	3,438	11,795	5,897	76	887	903	17
32	Total	27,046	162,424	81,212	1,679	18,791	27,872	9,081

Data Sources:

1. EAB_WP07DR RB Pro Forma Post Test Year Plant Additions, "PTYP ADIT (18 Mo) - FED" tab.

2. EAB_WP07DR RB Pro Forma Post Test Year Plant Additions, "PTYP (18 Mo) - ST" tab.

3. Derived from EAB_WP07DR RB Pro Forma Post Test Year Plant Additions, "PTYP ADIT (18 Mo) - FED" and "PTYP ADIT (18 Mo) - ST" tabs.

AECC TY 2015 Plant ADIT Adjustment Derivation

					50%		35%	
Line No.		APS Jan 2016 -Jun 2017 Depr Est.[1]	Tax Year 2016 Depreciation Expense Federal[2]	Tax Year 2017 Depreciation Expense - Federal[2]	Apportioned Jan.-Jun. 2017 Depreciation Expense - Federal	Accrued Federal Tax Depreciation Jan. 2016 - Jun 2017	AECC Federal Deferred Tax Liability Increase/(decrease)	APS Federal Deferred Tax Liability Increase/(decrease)
1	Distribution	202,554,861	117,789,405	109,242,324	54,621,162	172,410,567	(10,550,503)	(18,789,804)
2	General & intangible	160,124,940	46,348,151	31,567,016	15,783,508	62,131,659	(34,297,648)	(36,678,504)
3	Nuclear	72,549,654	20,712,704	19,835,250	9,917,625	30,630,329	(14,671,764)	(16,167,783)
4	Solar	42,132,891	33,004,129	22,102,157	11,051,079	44,055,208	672,811	(994,184)
5	Gen (non Nuclear)	211,737,231	67,681,082	63,791,797	31,895,899	99,576,981	(39,256,088)	(44,067,408)
6	Transmission	74,743,147	55,406,482	52,060,127	26,030,064	81,436,546	2,342,689	(1,583,802)
7	Total	763,842,724	340,941,953	298,598,671	149,299,336	490,241,289	(95,760,502)	(118,281,485)

					50%		3.10%		
		APS Jan 2016 -Jun 2017 Depr Est.[1]	Tax Year 2016 Depreciation Expense - State[2]	Tax Year 2017 Depreciation Expense - State[2]	Apportioned Jan.-Jun. 2017 Depreciation Expense - State	Accrued State Tax Depreciation Jan. 2016 - Jun 2017	AECC State Deferred Tax Liability Increase/(decrease)	APS State Deferred Tax Liability Increase/(decrease)	Total AECC ADIT Adjustment
8	Distribution	202,554,861	175,467,146	159,929,827	79,964,914	255,432,060	1,639,193	570,821	9,307,674
9	General & intangible	160,124,940	87,563,318	57,507,314	28,753,657	116,316,975	(1,358,047)	(1,742,210)	2,765,019
10	Nuclear	72,549,654	31,419,954	29,829,890	14,914,945	46,334,899	(812,657)	(1,011,929)	1,695,290
11	Solar	42,132,891	88,892,949	52,129,431	26,064,716	114,957,665	2,257,568	1,909,330	2,015,232
12	Gen (non Nuclear)	211,737,231	93,521,292	87,433,704	43,716,852	137,238,144	(2,309,472)	(2,893,551)	5,395,400
13	Transmission	74,743,147	89,955,092	84,745,159	42,372,580	132,327,672	1,785,120	1,219,001	4,492,611
14	Total	763,842,724	566,819,751	471,575,325	235,787,663	802,607,414	1,201,705	(1,948,539)	25,671,226

Data Sources:

1. EAB_WP07DR RB Pro Forma Post Test Year Plant Additions.

2. APS's Response to AECC Data Request 9.3.

EXHIBIT KCH-10

2011 Vertically-Integrated Electric Utility Rate Case Summary
Cases with ROE Determinations as Reported by SNL Financial

Decision Date	State	Company	Case Identification	Common Equity /Total Cap (%)	Return on Equity (%)
1/5/2011	Oklahoma	Public Service Co. of OK	Ca-PUD201000050	45.84	**10.15**
1/12/2011	Wisconsin	Madison Gas and Electric Co.	D-3270-UR-117 (elec)	58.06	**10.30**
1/13/2011	Wisconsin	Wisconsin Public Service Corp.	D-6690-UR-120 (elec)	51.65	**10.30**
2/25/2011	Hawaii	Hawaiian Electric Co.	D-2008-0083	55.81	**10.00**
3/25/2011	Washington	PacifiCorp	D-UE-100749	49.10	**9.80**
3/30/2011	West Virginia	Appalachian Power Co.	C-10-0699-E-42T	42.20	**10.00**
4/12/2011	Missouri	Kansas City Power & Light	C-ER-2010-0355	46.30	**10.00**
4/25/2011	Minnesota	Otter Tail Power Co.	D-E-017/GR-10-239	51.70	**10.74**
4/27/2011	Indiana	Southern Indiana Gas & Elec Co	Ca-43839	43.46	**10.40**
5/4/2011	Missouri	KCP&L Greater Missouri Op Co	C-ER-2010-0356 (MPS)	46.58	**10.00**
5/4/2011	Missouri	KCP&L Greater Missouri Op Co	C-ER-2010-0356 (L&P)	46.58	**10.00**
6/8/2011	North Dakota	MDU Resources Group Inc.	C-PU-10-124	53.34	**10.75**
6/17/2011	Arkansas	Oklahoma Gas and Electric Co.	D-10-067-U	34.90	**9.95**
7/13/2011	Missouri	Union Electric Co.	C-ER-2011-0028	52.24	**10.20**
8/8/2011	New Mexico	Public Service Co. of NM	C-10-00086-UT	51.28	**10.00**
8/11/2011	Utah	PacifiCorp	D-10-035-124	51.90	**10.00**
8/12/2011	Minnesota	Interstate Power & Light Co.	D-E-001/GR-10-276	47.74	**10.35**
9/2/2011	Alaska	Alaska Electric Light Power	D-U-10-029	53.80	**12.88**
9/22/2011	Wyoming	PacifiCorp	D-20000-384-ER-10	52.30	**10.00**
10/20/2011	Michigan	DTE Electric Co.	C-U-16472	40.26	**10.50**
12/20/2011	Michigan	Upper Peninsula Power Co.	C-U-16417	45.74	**10.20**
12/21/2011	Indiana	Northern IN Public Svc Co.	Ca-43969	46.53	**10.20**
12/22/2011	Colorado	Black Hills Colorado Electric	D-11AL-387E	49.10	**9.90**
12/22/2011	Wisconsin	Northern States Power Co - WI	D-4220-UR-117 (elec)	52.59	**10.40**
12/23/2011	Nevada	Nevada Power Co.	D-11-06006	44.38	**10.19**
			MEDIAN:		**10.19**
			OBSERVATIONS:		**25**

2015 Vertically-Integrated Electric Utility Rate Case Summary
Cases with ROE Determinations as Reported by SNL Financial

Decision Date	State	Company	Case Identification	Common Equity /Total Cap (%)	Return on Equity (%)
1/23/2015	Wyoming	PacifiCorp	D-20000-446-ER-14	51.43	**9.50**
2/24/2015	Colorado	Public Service Co. of CO	D-14AL-0660E	56.00	**9.83**
3/25/2015	Washington	PacifiCorp	D-UE-140762	49.10	**9.50**
3/26/2015	Minnesota	Northern States Power Co. - MN	D-E-002/GR-13-868	52.50	**9.72**
4/23/2015	Michigan	Wisconsin Public Service Corp.	C-U-17669	NA	**10.20**
4/29/2015	Missouri	Union Electric Co.	C-ER-2014-0258	51.76	**9.53**
5/26/2015	West Virginia	Appalachian Power Co.	C-14-1152-E-42T	47.16	**9.75**
9/2/2015	Missouri	Kansas City Power & Light	C-ER-2014-0370	50.09	**9.50**
9/10/2015	Kansas	Kansas City Power & Light	D-15-KCPE-116-RTS	50.48	**9.30**
11/19/2015	Wisconsin	Wisconsin Public Service Corp.	D-6690-UR-124 (Elec)	50.47	**10.00**
11/19/2015	Michigan	Consumers Energy Co.	C-U-17735	41.50	**10.30**
12/3/2015	Wisconsin	Northern States Power Co - WI	D-4220-UR-121 (Elec)	52.49	**10.00**
12/11/2015	Michigan	DTE Electric Co.	C-U-17767	38.03	**10.30**
12/15/2015	Oregon	Portland General Electric Co.	D-UE-294	50.00	**9.60**
12/17/2015	Texas	Southwestern Public Service Co	D-43695	51.00	**9.70**
12/18/2015	Idaho	Avista Corp.	C-AVU-E-15-05	50.00	**9.50**
12/30/2015	Wyoming	PacifiCorp	D-20000-469-ER-15	51.44	**9.50**
			MEDIAN:		**9.70**
			OBSERVATIONS:		17

2016 (11 Months) Vertically-Integrated Electric Utility Rate Case Summary
Cases with ROE Determinations as Reported by SNL Financial

Decision Date	State	Company	Case Identification	Common Equity /Total Cap (%)	Return on Equity (%)
1/6/2016	Washington	Avista Corp.	D-UE-150204	48.50	**9.50**
2/23/2016	Arkansas	Entergy Arkansas Inc.	D-15-015-U	28.46	**9.75**
3/16/2016	Indiana	Indianapolis Power & Light Co.	Ca-44576	37.33	**9.85**
6/8/2016	New Mexico	El Paso Electric Co.	C-15-00127-UT	49.29	**9.48**
7/18/2016	Indiana	Northern IN Public Svc Co.	Ca-44688	47.42	**9.98**
8/9/2016	Tennessee	Kingsport Power Company	D-16-00001	40.25	**9.85**
8/18/2016	Arizona	UNS Electric Inc.	D-E-04204A-15-0142	52.83	**9.50**
9/1/2016	Washington	PacifiCorp	D-UE-152253	49.10	**9.50**
9/8/2016	Michigan	Upper Peninsula Power Co.	C-U-17895	53.49	**10.00**
9/28/2016	New Mexico	Public Service Co. of NM	C-15-00261-UT	49.61	**9.58**
11/9/2016	Wisconsin	Madison Gas and Electric Co.	D-3270-UR-121 (Elec)	NA	**9.80**
11/10/2016	Oklahoma	Public Service Co. of OK	Ca-PUD201500208	44.00	**9.50**
11/18/2016	Wisconsin	Wisconsin Power and Light Co	D-6680-UR-120 (Elec)	NA	**10.00**
11/29/2016	Florida	Florida Power & Light Co.	D-160021-EI	NA	**10.55**
			MEDIAN:		**9.78**
			OBSERVATIONS:		14

EXHIBIT KCH-11 (Confidential)

Exhibit Intentionally Omitted – Contains Confidential Information